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STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY FOR (1) AUTHORITY TO MODIFY ITS RATES AND CHARGES FOR GAS UTILITY SERVICE THROUGH A PHASE IN OF RATES; (2) MODIFICATION OF THE SETTLEMENT AGREEMENTS APPROVED IN CAUSE NO. 43894; (3) APPROVAL OF NEW SCHEDULES OF RATES AND CHARGES, GENERAL RULES AND REGULATIONS, AND RIDERS; (4) APPROVAL OF REVISED DEPRECIATION RATES APPLICABLE TO ITS GAS PLANT IN-SERVICE; (5) APPROVAL OF NECESSARY AND APPROPRIATE ACCOUNTING RELIEF; AND (6) AUTHORITY TO IMPLEMENT TEMPORARY RATES CONSISTENT WITH THE PROVISIONS OF IND. CODE CH. 8-1-2-42.7.	)	**CAUSE NO. 44988** **APPROVED:** SEP 19 2018

ORDER OF THE COMMISSION

Presiding Officers:
David E. Ziegner, Commissioner
Lora L. Manion, Administrative Law Judge

On September 27, 2017, Northern Indiana Public Service Company LLC ("NIPSCO," "Petitioner," or "Company") filed its Verified Petition for General Rate Increase and Associated Relief under Ind. Code §§ 8-1-2-61 and 8-1-2-42.7, Notice of Provision of Information in Accordance with the Commission's Minimum Standard Filing Requirements and Request for Administrative Notice with the Indiana Utility Regulatory Commission ("Commission"). On September 27, 2017, Petitioner also filed its case-in-chief, work papers, administrative notice documents, and information required by the Minimum Standard Filing Requirements ("MSFRs") set forth in 170 IAC 1-5-1 through 16. On November 29, 2017, the Presiding Officers granted Petitioner's Request for Administrative Notice.

NIPSCO provided testimony and exhibits from the following witnesses:[1]

- Violet Sistovaris, President of NIPSCO and Executive Vice President of NiSource Inc., the parent company of NIPSCO ("NiSource")

[1] NIPSCO also filed Petitioner's Confidential Exhibit No. 17 providing support for its accounting adjustments.

- Frank A. Shambo, Senior Vice President of Regulatory and Legislative Affairs with NIPSCO[2]

- June M. Konold, Vice President of Regulatory Strategy and Support with NiSource Corporate Services Company ("NCSC")[3]

- Clifton Scott, State Finance Director with NIPSCO

- Albert A. Stone, Vice President and General Manager with NIPSCO

- James S. Roberts, Director of Pipeline Safety with NCSC

- Andrew S. Campbell, Director of Regulatory Support & Planning with NIPSCO

- Ronald J. Harper, Director of Corporate Budgets with NCSC

- Christopher D. Smith, Vice President of Human Resources with NCSC

- John J. Spanos, Senior Vice President with Gannett Fleming Valuation and Rates Consultants, LLC

- Ann E. Bulkley, Senior Vice President of Concentric Energy Advisors, Inc. ("Concentric")

- Michael D. McCuen, Director of Income Taxes with NCSC

- Vincent V. Rea, Director of Regulatory Finance and Economics with NiSource

- Amy Efland, Manager of Demand Forecasting with NCSC

- Ronald J. Amen, Director with Black & Veatch Management Consulting, LLC ("Black & Veatch")

- Curt A. Westerhausen, Director of Regulatory with NCSC

- Patrick L. Baryenbruch, President of Baryenbruch & Company, LLC

Petitions to intervene were granted to the following parties, without objection:

- Citizens Action Coalition of Indiana, Inc. ("CAC")

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[2] NIPSCO originally filed direct and rebuttal testimony of Timothy R. Caister. NIPSCO filed a Notice of Substitution of Witness on April 19, 2018.

[3] NIPSCO originally filed direct and supplemental testimony of Derric J. Isensee. NIPSCO filed a Notice of Substitution of Witness on March 26, 2018.

- Direct Energy Business Marketing, LLC and its affiliate Direct Energy Services, LLC (together "Direct Energy")

- EDF Energy Services, LLC ("EDFES")

- Gas Supplier Group ("GSG")[4]

- The NIPSCO Industrial Group ("Industrial Group")[5]

- Steel Dynamics, Inc. ("SDI")

- United Steel, Paper and Forestry, Rubber, Manufacturing, Energy, Allied Industrial and Service Workers International Union, AFL-CIO/CLC

By docket entry dated November 9, 2017, the Presiding Officers established a procedural schedule in this matter.[6] The Commission conducted public field hearings on December 11, 2017, at Grand Wayne Convention Center in Fort Wayne; January 3, 2018, at Merrillville High School in Merrillville; and February 5, 2018, at South Bend Century Center in South Bend. At the field hearings, members of the public were afforded an opportunity to make statements to the Commission.

On March 2, 2018, the Indiana Office of Utility Consumer Counselor ("OUCC") and Intervenors filed their respective cases-in-chief. On March 2, 2018, the OUCC filed a Motion for Administrative Notice, and on March 19, 2018, the Presiding Officers granted the Motion.[7] On March 2, 2018, GSG filed a Motion for Administrative Notice, and on March 19, 2018, the Presiding Officers granted the Motion.[8]

The OUCC provided testimony and exhibits from the following witnesses:

- Mark H. Grosskopf, Senior Utility Analyst

- Isabelle L. Gordon, Utility Analyst

- Mark P. Dermody, Utility Analyst

- Amy E. Larsen, Utility Analyst II

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[4] The companies that comprise the Gas Supplier Group are CenterPoint Energy, Inc. and Retail Energy Supply Association.

[5] The companies that comprise the NIPSCO Industrial Group are Arcelor Mittal USA, Arconic, Inc., BP Products North America, Inc., Cargill, Inc., Fiat Chrysler Automobiles, General Motors LLC, NLMK Indiana, Praxair, Inc., Rea Magnet Wire Company, Inc., United States Steel Corporation, and USG Corporation.

[6] The procedural schedule was modified by docket entry dated November 29, 2017.

[7] The Motion requested administrative notice of the the following: (i) the final orders in Cause Nos. 44403 TDSIC-7, 44970, 45032 dated Jan. 3, 2018, and Feb. 16, 2018; (ii) the transcript of the evidentiary hearing in Cause No. 44403 TDSIC-7 on Nov. 30, 2017; (iii) NIPSCO's redacted direct testimony in Cause No. 45007 on Nov. 8, 2017; and (iv) the Presiding Officers' docket entry in Cause No. 45032 dated January 23, 2018.

[8] The Motion requested administrative notice of the following final Orders in Cause Nos. 40342, 42097, 40342, and consolidated 42884 and 42800.

- Farheen Ahmed, Utility Analyst II
- Edward T. Rutter, Chief Technical Advisor
- Bradley E. Lorton, Utility Analyst
- Brien R. Krieger, Utility Analyst

CAC provided testimony and exhibits from the following witness:

- Kerwin L. Olson, Executive Director with CAC

The Industrial Group provided testimony and exhibits from the following witnesses:

- Michael P. Gorman, Managing Principal with Brubaker & Associates
- Nicholas Phillips, Jr., Principal with Brubaker & Associates

SDI provided testimony and exhibits from the following witness:

- Kevin C. Higgins, Principal with Energy Strategies, LLC

On March 28, 2018, NIPSCO filed its rebuttal testimony and Industrial Group filed its cross-answering testimony.

On April 20, 2018, NIPSCO, the OUCC, the Industrial Group, GSG, SDI, EDFES, and Direct Energy (the "Settling Parties") filed a Stipulation and Settlement Agreement (the "Settlement") and testimony in support of the Settlement. A copy of the Settlement is attached hereto. On May 4, 2018, CAC filed testimony in opposition to the Settlement. On May 11, 2018, the Settling Parties filed settlement reply testimony. By docket entry dated May 18, 2018, the Presiding Officers requested information from NIPSCO, to which NIPSCO responded on May 22, 2018. On May 24, 2018, CAC filed its Stipulation in Lieu of Cross-Examination. By docket entry dated May 25, 2018, the Presiding Officers requested additional information from NIPSCO, to which NIPSCO responded on May 25, 2018.

Pursuant to notice given and published as required by law, the Commission conducted an evidentiary hearing in Room 222 beginning at 9:30 a.m. on May 29, 2018. All parties presented their evidence and all parties waived cross examination.

TABLE OF CONTENTS

The Commission, based upon the applicable law and evidence presented, now finds:

1. Notice and Jurisdiction. Notice of the filing of the Petition in this Cause was given and published by NIPSCO as required by law. Notice was given by NIPSCO to its customers summarizing the nature and extent of the proposed changes in its rates and charges for gas service. Notices of the public hearings in this Cause were given and published as required by law. NIPSCO is a public utility as defined in Ind. Code § 8-1-2-1(a). NIPSCO is also a gas utility as defined in Ind. Code § 8-1-2-87(a)(4). NIPSCO is also a utility within the meaning of Ind. Code § 8-1-2-42.7(c). Pursuant to Ind. Code § 8-1-2-42 and Ind. Code § 8-1-2-42.7, the Commission has jurisdiction over NIPSCO's rates and charges for utility service. Therefore, the Commission has jurisdiction over NIPSCO and the subject matter of this proceeding.

2. Petitioner's Characteristics. NIPSCO is a public utility with its principal office and place of business at 801 East 86th Avenue, Merrillville, Indiana and provides gas ("NIPSCO") and electric service ("NIPSCO Electric") in Indiana. NIPSCO is authorized by the Commission to provide gas utility service to the public in all or part of Adams, Allen, Benton, Carroll, Cass, Clinton, DeKalb, Elkhart, Fulton, Howard, Huntington, Jasper, Kosciusko, LaGrange, Lake, LaPorte, Marshall, Miami, Newton, Noble, Porter, Pulaski, St. Joseph, Starke, Steuben, Tippecanoe, Tipton, Wabash, Warren, Wells, White, and Whitley Counties in northern Indiana.

3. Existing Rates. The Commission's November 4, 2010 Order in Cause No. 43894 approved a Stipulation and Settlement Agreement between NIPSCO, the OUCC, the Industrial Group,[9] NIPSCO Marketer Group ("Marketer Group"),[10] and CAC (the "2010 Rate Case Settlement") establishing NIPSCO's current basic rates and charges and depreciation rates ("2010 Rate Case Order"). *N. Indiana Pub. Serv. Co.,* Cause No. 43894, 2010 WL 4499410 (IURC Nov. 4, 2010).

The Commission's May 31, 2011 Order in Consolidated Cause Nos. 43941, 43942, and 43943 approved a Stipulation and Settlement Agreement between NIPSCO, the OUCC, and the Marketer Group whereby the former Kokomo Gas & Fuel Company and Northern Indiana Fuel & Light Company Inc. were merged into NIPSCO, and the rates approved in the 2010 Rate Case Order were made applicable to customers across the footprint of the consolidated company (the "Merger Order"). *N. Indiana Pub. Serv. Co., Kokomo Gas & Fuel Co., and N. Indiana Fuel & Light Co.,* Cause No. 43941, 2011 WL 2287660 (IURC May 31, 2011). The Merger Order also approved an addition to the authorized net operating income ("NOI") of the consolidated company resulting in a total authorized NOI of $44,443,966.

The Commission's August 28, 2013 Order in Cause No. 43894 (the "2013 Extension Order") approved a Stipulation and Settlement Agreement between the parties, modifying and extending the 2010 Settlement (the "2013 Extension Agreement"). *N. Indiana Pub. Serv. Co.,* Cause No. 43894, 2013 WL 4737978 (IURC Aug. 28, 2013). The 2013 Extension Order approved the parties' agreement that the 2013 Extension Agreement shall be subject to review no earlier

[9] In Cause No. 43894, Industrial Group consisted of Arcelor Mittal USA, Beta Steel Corporation, Praxair, Inc., and United States Steel Corporation.
[10] In Cause No. 43894, the Marketer Group consisted of Border Energy, Vectren Retail, LLC, and Nordic Energy Services, LLC.

than May 1, 2017, and that NIPSCO's basic rates and charges should remain in effect through November 4, 2020, or further Order of the Commission.

Those basic rates and charges remain in effect today, as modified, including modification by various riders approved by the Commission. The petition initiating Cause No. 43894 was filed with the Commission on May 3, 2010. Therefore, in accordance with Ind. Code § 8-1-2-42(a), more than 15 months have passed since the filing date of NIPSCO's most recent request for a general increase in its basic rates and charges.

4. **Relief Requested.** NIPSCO's Petition requests approval of the following:

A. **Gas Service Tariff and Standard Contract.** NIPSCO seeks approval of changes to its basic rates and charges for gas utility service that will provide NIPSCO with the opportunity to earn a fair return on the fair value of its property. NIPSCO seeks approval of changes to its Gas Service Tariff, including changing from Series 400 Rate Schedules to Series 100 Rate Schedules, revising its Standard Contract, instituting a new Automated Meter Reading ("AMR") Opt-Out Charge, and miscellaneous changes to its General Rules and Regulations and Standard Contract for improved clarity and administrative simplification. The overall structure of NIPSCO's tariffs largely remains the same, but NIPSCO is seeking a change to the structure of its gas transportation Rates 128 and 138 (currently Rates 428 and 438), as well as other changes such as changes to Rule 13, and Riders 131 and 189.

B. **Modification of the 2010 Rate Case Settlement and 2013 Extension Agreement.** NIPSCO seeks approval of the modification of the 2010 Rate Case Settlement and 2013 Extension Agreement to the extent necessary to implement the relief requested in this proceeding including without limitation authority to eliminate the depreciation credit mechanism incorporated into those agreements.

C. **Depreciation Rates.** NIPSCO seeks approval to revise its gas depreciation rates applicable to its gas plant in-service. NIPSCO continues to use the depreciation rates applicable to its common plant as approved by the Commission in NIPSCO's last electric general rate proceeding in Cause No. 44688. *N. Indiana Pub. Serv. Co.,* Cause No. 44688, 2015 WL 7429492 (IURC Nov. 18, 2015).

D. **Accounting Relief.** As explained in NIPSCO's case-in-chief, NIPSCO seeks accounting authority to implement the relief sought in this proceeding.

E. **Gas DSM.** NIPSCO proposes to exclude from its basic rates and charges all costs associated with its gas demand side management ("DSM") and energy efficiency ("EE") program.

F. **Regulatory Assets.** NIPSCO proposes to recover through its revenue requirement certain costs NIPSCO has deferred in accordance with Commission Orders.

G. **Prepaid Pension Asset.** NIPSCO's pension plan is currently in a net Prepaid Pension Asset ("PPA") position because the forecasted amount of cumulative cash contributions to NIPSCO's pension trust fund exceeds the forecasted cumulative amount of pension expense. This is further discussed by NIPSCO's Ms. Konold. The PPA reduces the pension cost that would otherwise be reflected in the revenue requirement and preserves the integrity of the pension fund. NIPSCO proposes that for ratemaking purposes the PPA be included as a component of overall weighted average cost of capital ("WACC").

5. **Test Year.** NIPSCO proposed a forward-looking test period using projected data as authorized by Ind. Code § 8-1-2-42.7(d)(1). In the docket entry setting the procedural schedule, as modified, we found that the Forward Test Year to be used for determining NIPSCO's projected operating revenues, expenses, and operating income shall be the 12-month period ending December 31, 2018. The Historical Base Period shall be the 12-month period ending December 31, 2016.

6. **Overview of the Settlement.** The Settling Parties testified that the Settlement fairly and reasonably resolves all issues in this Cause, subject to Commission approval without any modification or condition that is unacceptable to the Settling Parties. The Settlement addresses predication of settlement rates, revenue requirements, NOI, original cost rate base, capital structure, fair return, depreciation and amortization expense, 2017 Tax Act, regulatory treatment of Current Gas Alternative Regulatory Plan ("ARP") margins, cost allocation, rate design, tariff language, and certification of rates.[11]

The key terms of the Settlement are summarized as follows:

- NIPSCO will increase its basic rates and charges for natural gas utility service in three steps as follows:

  (1) Step One is based on the agreed revenue requirement as adjusted to reflect the original cost of NIPSCO's net utility plant in-service, actual capital structure, and associated depreciation expense as of June 30, 2018 ("Step One") to become effective on October 1, 2018;[12]

  (2) Step Two is based on the agreed revenue requirement as of December 31, 2018, as adjusted, if necessary, to reflect the lesser of the following: (i) NIPSCO's forecasted test-year-end rate base as updated in its rebuttal evidence ($1,520,209,700), or (ii) NIPSCO's certified test-year-end net plant in-service as of December 31, 2018, ("Step Two") to go into effect for usage beginning on the date that NIPSCO certifies its test-year-end net plant in-service, or January 1, 2019, whichever is later; and

  (3) Step Three passes back unprotected excess Accumulated Deferred Income Taxes ("ADIT") to customers beginning January 1, 2020, over a 12-year amortization period ("Step Three") to become effective on January 1, 2020, based on a compliance filing to be made by NIPSCO prior to that date.

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[11] The Settlement also resolves all issues currently pending in Cause No. 45007. The Settlement has been filed in that Cause.

[12] Assuming a Final Order is issued in this Cause on or about September 24, 2018.

- NIPSCO's base rates will be designed to produce annual revenue requirements of $726,671,093, less $6,855,023 of Other Revenues, which represents a decrease of $48,958,762 from the amount originally requested by NIPSCO.

- NIPSCO's authorized NOI will be $98,813,631.

- NIPSCO has agreed that its weighted cost of capital times its original cost rate base yields a fair return for purposes of this case, and the Settling Parties agree to the following: (i) that NIPSCO should be authorized a fair return of no more than $98,813,631 yielding an overall return for earnings test purposes of 6.50%; (ii) NIPSCO's original cost rate base is $1,520,209,700, inclusive of gas in underground storage, materials and supplies, and a Transmission, Distribution, and Storage System Improvement Charge ("TDSIC") Regulatory Asset as proposed in NIPSCO's case-in-chief; (iii) NIPSCO's capital structure is as set forth below; and (iv) NIPSCO's authorized return on equity ("ROE") is 9.85%.

- NIPSCO's overall WACC is computed as follows:

	% of Total	**Cost %**	**WACC %**
Common Equity	46.88%	9.85%	4.62%
Long-Term Debt	36.80%	4.94%	1.82%
Customer Deposits	1.22%	4.91%	0.06%
Deferred Income Taxes	21.10%	0.00%	0.00%
Prepaid Pension Asset	-7.43%	0.00%	0.00%
Post-Retirement Liability	1.39%	0.00%	0.00%
Post-1970 ITC	0.04%	7.69%	0.00%
Totals	**100.0%**		**6.50%**

- The depreciation accrual rates recommended by NIPSCO Witness Mr. Spanos and presented in this proceeding (the "Depreciation Study") will be used in the determination of net plant in-service values for the calculation of Step One, Step Two, and Step Three rates. NIPSCO continues to use the depreciation rates applicable to its common plant as approved by the Commission in NIPSCO's last electric general rate proceeding in Cause No. 44688.

- Amortization of regulatory assets for rate case expense and the TDSIC deferred balance will be over a period of seven years. For rate case expense, the annual amortization expense shall reflect a reduction of $140,000 from that proposed in NIPSCO's case-in-chief. If not already addressed by an intervening base rate case Order, after the completion of the seven-year period, NIPSCO agrees to make a tariff filing that will reflect the reduction in amortization expense as a result of the end of rate case expense and TDSIC deferred balance amortization.

- Treatment of excess income taxes occasioned by the 2017 Tax Act are as follows:

  (1) NIPSCO agrees to revise its base rates and charges consistent with the revised tariffs that NIPSCO filed on March 26, 2018, and NIPSCO will not request a subdocket in Phase One of Cause No. 45032.

  (2) The treatment of excess income taxes and excess deferred income tax balances occasioned by the 2017 Tax Act are as follows: (i) NIPSCO will return excess income tax revenue recovered through base rates and any applicable charges between January 1, 2018 and April 30, 2018 (assuming approval of its March 26, 2018 tariffs on or around April 25, 2018) currently reflected as a regulatory liability in accordance with the January 3, 2018 Order initiating Cause No. 45032 over a six-month period beginning January 1, 2019 through its approved TDSIC mechanism in Cause No. 44403 TDSIC-9 to be filed on or before September 1, 2018. Other than the excess income tax collected through the TDSIC, which should be allocated based on the allocation methodology used in that tracker, the allocation of the remaining excess income tax amounts between rate classes will be addressed in Cause No. 44403 TDSIC-9 and is not governed by this Settlement; (ii) As of December 31, 2017, NIPSCO recorded protected excess ADIT of $24,169,649. NIPSCO will continue to utilize the average rate assumption method ("ARAM") to pass back to customers. NIPSCO will record the differences between ARAM and the amortization passed back through base rates (estimated using a 45.8 year amortization period) as a regulatory asset or liability for treatment in NIPSCO's next base rate case; and (iii) As of December 31, 2017, NIPSCO recorded unprotected excess ADIT of $73,743,924. NIPSCO will pass it back to customers beginning January 1, 2020, over a 12-year amortization period. NIPSCO agrees to make a compliance filing in Cause No. 44988 in late 2019 to show the calculation of the reduced rates to be effective January, 2020. The Settling Parties represent that the Settlement resolves all issues in Phase Two of Cause No. 45032.

- The regulatory treatment of NIPSCO's margins associated with NIPSCO's Current Gas ARP programs remain unchanged.

- The Settling Parties agree that rates should be designed to allocate the revenue requirement to and among NIPSCO's customer classes in a fair and reasonable manner that is consistent with cost causation principles. The Settling Parties agree that NIPSCO should design its rates using the structure of its proposed 100 Series tariffs in the manner described below:

  - NIPSCO will implement a Customer Charge of $14.00 per month along with a Distribution Charge based on consumption for Residential Customers taking service under Rate 111 – Residential Service. For Step Three rates, the overall impact on the Residential Service class will result in a $68,485,505 increase in revenue, which equals a 36.21% increase to the class.[13]

- NIPSCO will implement a Customer Charge of $17.50 per month along with a Distribution Charge based on consumption for residential customers taking service under Rate 115 – Multiple Family Housing Service. For Step Three rates, the overall impact on the Multiple Family Housing Service class will result in a $59,064 increase in revenue, which equals a 2.72% increase to the class.

- NIPSCO will implement a Customer Charge of $53.00 per month along with a Distribution Charge based on consumption for Small Non-Residential Customers. For Step Three rates, the overall impact on the General Service Small class will result in a $23,580,422 increase in revenue, which equals a 37.70% increase to the class.

- NIPSCO will implement a Customer Charge of $400.00 per month along with a Distribution Charge based on consumption for Large Non-Residential Customers. For Step Three rates, the overall impact on the General Service Large class will result in a $2,926,525 increase in revenue, which equals a 27.47% increase to the class.

- Rate 128 – Large Firm Transportation and Balancing Service will be for a firm service. It will be a three-part rate consisting of a customer/meter charge of $1,000.00, a demand charge that targets to recover 10% of the fixed costs allocated to the rate class, and a volumetric charge. For Step Three rates, the overall impact on the Rate 128 class will be a $10,721,786 increase in revenue, which equals a 38.98% increase to the class. The Settling Parties agree that Rate 128 will be divided into two sub-rates reflecting distinct cost allocation between the sub-rates but with no impact on any rate classes outside of Rate 128. The sub-rates shall be designated Rate 128 HP, designating those Rate 128 customers served exclusively from facilities at or above 60 pounds per square inch ("PSIG"), and Rate 128 DP, all other Rate 128 customers. The demand charges for Rate 128 high pressure and distribution pressure sub-rates will be subject to an annual update to reflect recovery of $2,549,903 for 128 HP and $805,239 for 128 DP from the total rate class based upon the class demand determinants from the preceding winter season (December, January, and February). The Settling Parties agree that the update process for demand charges is a mechanism for compromise and should not be treated in future proceedings as an endorsement as to methodology.

- Rate 138 – General Transportation and Balancing Service will also be a three-part rate consisting of a customer/meter charge of $750.00, a demand charge that targets to recover 10% of the fixed costs allocated to the rate class, and a volumetric charge. For Step Three rates, the overall impact on

[13] All references to increases in revenue dollars and percentages reflect an assumption that the revised rates pursuant to the Phase One filing in Cause No. 45032 are approved and implemented as filed.

the Rate 138 class is a \$1,325,439 increase in revenue, which equals a 38.93% increase to the class. The demand charge for Rate 138 will be subject to an annual update to reflect recovery of \$250,161 from the rate class based upon the class demand determinants from the preceding winter season (December, January, and February). The Settling Parties agree that the update process for demand charges is a mechanism for compromise and should not be treated in future proceedings as an endorsement as to methodology.

- NIPSCO requests authorization to increase all fixed monthly charges not specifically discussed above as to which NIPSCO had proposed an increase in this proceeding (including, but not limited to, the bank capacity charge) by no more than 25%.

- The proposed language changes to NIPSCO's Schedules of Rates and Riders Applicable to Gas Service (including changes to Rates 128 and 138 and Riders 131 and 189, which were subject to revision and clarification following negotiations) are attached to NIPSCO Witness Mr. Curt Westerhausen's Settlement Testimony as Pet. Ex. 16-S, Attach. 16-S-A, including the illustrative rates for Step One, Step Two, and Step Three in Attach. 16-S-D. With regard to Rider 189, NIPSCO agrees that (1) no existing customer will be required to receive service under Rider 189 based on current usage patterns; (2) existing balancing services will not be reduced for purposes of determining undue burden; and (3) unless a material change in circumstance significantly increases intraday swings resulting in substantial penalties on a persistent basis over an extended period of time, an existing customer will not be required to take service under Rider 189.

- The proposed changes to NIPSCO's General Rules and Regulations Applicable to Gas service (including changes to Rule 13, which were subject to revision and clarification following negotiations) are attached to Mr. Westerhausen's Settlement Testimony as Pet. Ex. 16-S, Attach. 16-S-A.

- The Settling Parties represent that the cost allocation herein results in fair and reasonable rates and charges (Jt. Ex. D, Settlement Revenue Requirement Mitigation). Regarding the TDSIC Tracker, this mechanism shall utilize the allocators set forth in Joint Exhibit E, Gas TDSIC Allocators. Regarding the Federally Mandated Cost Adjustment ("FMCA") Tracker, and solely for purposes of Cause No. 45007 (the "Gas FMCA Proceeding"),[14] this mechanism shall utilize the allocators set forth in Joint Exhibit F, Gas FMCA Allocators. In the event NIPSCO seeks to modify the allocation percentages to reflect significant migrations of customers amongst the various rate classes in order to prevent any unintended

[14] On November 8, 2017, NIPSCO filed its Verified Petition initiating a request for approval of a certificate of public convenience and necessity for a Pipeline Safety Compliance Plan ("Pipeline Plan") to comply with certain federal pipeline safety performance standards and regulations pursuant to the provisions of Ind. Code ch. 8-1-8.4 and seeking associated ratemaking treatment for costs associated with the Pipeline Plan.

consequences of the migration of customers and to reasonably allocate their estimated share of the revenue requirement, NIPSCO agrees to identify such modifications in pre-filed testimony and provide supporting testimony. The Settling Parties reserve the right to conduct discovery and raise issues with any proposed modification. Settlement at 18.

7. NIPSCO's Case-in-Chief.

A. Violet Sistovaris. Ms. Sistovaris, President of NIPSCO and Executive Vice President of NiSource, provided a brief overview of NIPSCO and its role in northern Indiana. She provided an overview of NiSource and its aspiration to become the premier regulated energy company in North America with the following: (i) top-tier safety, customer service, and reliability metrics; (ii) a solid foundation of engaged, aligned, and safe employees; and (iii) a strong financial profile, a wide range of investment-driven growth, and robust and sustainable earnings and cash flow. She described the NiSource corporate structure and described the three core objectives of the NiSource strategic vision: (i) investment in needed infrastructure programs; (ii) strengthen the financial foundation for access to capital to continue making ongoing investments in-service quality, environmental, and reliability; and (iii) enhancement of processes, performance, safety, and reliability across the operating companies to provide improved customer service. She explained how that vision applies to NIPSCO.

Ms. Sistovaris testified NIPSCO has taken a number of steps to improve its safety performance, including its performance in reducing third-party damages to its underground gas facilities. She stated NIPSCO anticipates increases in expenses associated with pipeline safety and damage prevention to support not only increased compliance requirements but also in furtherance of NIPSCO's commitment to industry-leading safety performance.

Ms. Sistovaris stated NIPSCO's commitment has been demonstrated in improvements in customer satisfaction and brand perception metrics. She noted that NIPSCO posted the largest increase in overall customer satisfaction among the nation's mid-sized electric utilities through the second quarter of 2016 as measured by J.D. Power and Associates and had recently learned that its J.D. Power overall customer satisfaction scores in the large gas utility segment also posted impressive performance increases. She stated that NIPSCO plans to introduce a number of service enhancements for its customers in the near future, including an enhanced and simplified web presence and introduction of improved billing and payment options. She noted that NIPSCO's low income program is also seen as a model of efficiency and effectiveness within Indiana.

Ms. Sistovaris testified NIPSCO's commitment to ongoing investments required to systematically and efficiently deliver service integrity has been demonstrated through the significant investment in gas utility transmission, distribution, and storage assets since its last rate case, including replacement of several large transmission projects and progress toward the elimination of the bare steel distribution lines in Gary, Indiana. She stated that since 2010, NIPSCO has invested more than $595 million in its transmission, distribution, and storage assets. These ongoing investments were required as a result of: (i) new delivery infrastructure to serve new customers; (ii) compliance with evolving standards for the safety of underground pipelines; and (iii) replacement of infrastructure to modernize systems and enhance capacity. She noted that NIPSCO continues to balance the need for new investments with the cost to its customers.

Ms. Sistovaris stated NIPSCO's commitment to provide dependable and timely service and emergency response is demonstrated by the substantial improvement in its gas emergency response rate to an average of 23 minutes. She stated NIPSCO has hired new facilities locate contractors to provide improved timeliness and accuracy in locating its underground gas facilities. NIPSCO also has an ongoing focus in connecting new customers. NIPSCO reviewed and improved its internal processes, developed employee training, and employed new technologies to now meet internal deadlines for the connection of new customers 90% of the time.

Ms. Sistovaris testified NIPSCO has added more than 27,500 customers since the close of the 2009 test year in its last rate case, with a significant number of those additions coming in the rural portions of its service territory where natural gas service was not previously available. Specifically, NIPSCO has seen especially strong growth in the Crown Point, Dyer, Demotte, Goshen, Plymouth, and Ft. Wayne areas. She noted that about 4,200 customers are projected to be added through the end of the 2018 Forward Test Year.

Ms. Sistovaris stated that in May of 2017 NiSource was named by *Forbes* magazine as one of America's Best Large Employers for the second consecutive year, #61 out of the 500 companies listed, and the top company in the utility segment. At that time, NIPSCO was recognized by *The Times of Northwest Indiana* as one of the three best places to work in northwest Indiana. She stated NIPSCO takes its employee relations seriously and has continued to pursue opportunities to enhance responsiveness and involvement by providing its employees with charitable and community outreach opportunities, support for employee training and development, and inclusion and diversity initiatives.

Ms. Sistovaris testified NiSource has continued to experience sustained growth in both earnings and dividends to which NIPSCO as an operating company has made a significant contribution. She stated that among NIPSCO's successes have been the ongoing investment in its gas and electric infrastructure and the successful execution of its ongoing environmental compliance efforts on the electric side of its business. She stated NIPSCO remains the lowest cost provider of natural gas service in Indiana and among the lowest in the nation, but ongoing investments in its workforce and increases in pipeline safety and depreciation expenses dictate that its overall basic rates and charges be increased for the first time since 1988.

Ms. Sistovaris explained the steps NIPSCO has taken to improve customer service. NIPSCO has taken advantage of feedback from its customers, employees, and other stakeholders to serve as the primary drivers behind many of the operational changes, improvements in customer communications, enhancements to services, and added programs and other offerings that have been implemented by NIPSCO. She stated that NIPSCO has also addressed estimated bills, one of the largest historical sources of dissatisfaction among NIPSCO customers. She noted that by the end of 2015, NIPSCO completed the replacement of nearly all natural gas meters with AMR technology to allow NIPSCO to substantially reduce if not eliminate estimated bills for all but the most severe weather periods. Ms. Sistovaris stated that NIPSCO also tracks feedback from customers that have been recently connected to assess how the experience went from a customer perspective. She stated the "Net Promoter" score tracks the percentage of customers stating that they would recommend NIPSCO as a service provider based on their experience. She noted that while the Net Promoter score is more typically used in competitive business, NIPSCO thinks it is valuable to understand how its initial customer experience is perceived and whether customers are satisfied. She noted that NIPSCO's focus on its customers has resulted in the fewest customer complaints per 1,000 customers at the Commission, and NIPSCO leads major utilities with the fewest justified complaints. She explained that NIPSCO is seeking to initiate a new program permitting bills to be paid by credit card with no additional fee charged for that convenience, a payment option that has been requested by customers.

Ms. Sistovaris testified that NIPSCO's current rates are insufficient to permit it to recover its ongoing cost of operation. She provided an overview of some of the challenges faced by NIPSCO, including the following: (i) increased federal pipeline safety requirements since NIPSCO's base rates were last thoroughly adjusted; (ii) NIPSCO's overall rate structure is based on conditions in the gas industry that predate the unbundling of the interstate pipeline network, and as a result, while those rates have been augmented and adjusted from time to time, they have not received a full "makeover" in several decades; and (iii) the depreciation expense reflected in NIPSCO's rates requires adjustment to reflect the current state of investment and condition.

B. **Frank A. Shambo.** Mr. Shambo, Senior Vice President of Regulatory and Legislative Affairs with NIPSCO, discussed the administrative aspects and regulatory implications of this rate case, the history of NIPSCO's current rates, and the key proposals. Mr. Shambo testified that the filing of this case satisfies the following: (i) the Commission's directive in the 2013 Extension Order that NIPSCO file a gas rate case by late 2020; and (ii) the requirement in Ind. Code § 8-1-39-9(d) that NIPSCO file a gas rate case "before the expiration of the public utility's approved seven-year plan."[15]

Mr. Shambo testified NIPSCO's current gas rates are not sufficient to permit NIPSCO to recover all of the costs of providing service to its customers. He stated NIPSCO's rate base has increased since its last rate case as NIPSCO has invested in its gas systems, thereby increasing depreciation and capital expenses. He stated NIPSCO's operations and maintenance ("O&M") expenses have also increased and are expected to increase further. He testified the expenses reflected in the Forward Test Year beginning January 1, 2018 and ending December 31, 2018 will be representative of the ongoing level of expenses incurred by NIPSCO.

Mr. Shambo testified NIPSCO is proposing to increase its revenues by $143.5 million, representing an overall increase of 22.7%, to be allocated among NIPSCO's customers according to the rate design and cost of service study proposed in this case. He stated NIPSCO is not proposing any changes in its basic service structure in this case noting that NIPSCO's gas rate classes continue to adequately serve the different customers that consume natural gas.

Mr. Shambo explained the steps NIPSCO took in the preparation of its case to mitigate the impact on specific customers and customer classes. He stated the cost of service study prepared by Mr. Amen identified the necessary revenue increases in each rate class to arrive at parity, and that NIPSCO then established mitigation parameters to further modify the results of the study in order to limit the impact of going to parity. He explained those mitigation objectives as follows: (i) no rate class's revenue allocation should decrease; (ii) no rate class's revenue allocation should increase by more than 150% of the system increase; (iii) all existing subsidies for major rate classes

[15] NIPSCO's TDSIC gas plan was approved in the Commission's April 30, 2014 Order in Cause No. 44403 ("Gas TDSIC Plan"), which expires at the end of 2020.

should be reduced to some degree; (iv) the percentage of each rate class's fixed costs that is currently recovered through a volumetric rate should decrease; (v) transportation rates should include a demand charge that recovers 25% of demand-related costs; (vi) those demand charges should be based on each class's average daily usage from December 1, 2015 through February 29, 2016; and (vii) any change in a rate or a charge should not violate the Commission's stated preference for gradualism. He testified that since NIPSCO's rates have not been fully reset on a cost of service basis since 1988, there are inter-class and intra-class subsidies that currently exist. He noted that while the elimination of inter-class subsidization is desirable, it was recognized that this objective must be made gradually.

Mr. Shambo stated that NIPSCO collaborated with its stakeholders prior to making the filing by reaching out, sharing information, and soliciting their input on key issues. NIPSCO met several times with the representatives of the settling parties to its last gas rate case filing over a five-month period to educate them on this filing, the issues driving it, and to listen to suggestions or concerns they might have. He stated NIPSCO seeks to promote simplicity, transparency, and collaboration with its stakeholders, respond to customers' needs, and reach a balanced set of proposals that are fair and reasonable.

Mr. Shambo described NIPSCO's proposal to include a $1,089,109 expense for credit card fees in its Forward Test Year revenue requirement (see Adjustment OM 9-18R) to cover the expected costs of providing customers with the option to pay their gas bills with a credit card without a fee. He stated this is a policy that is being rolled out by utilities across the nation as consumers increasingly expect to be able to pay their bills without a separate credit card charge.

Mr. Shambo testified NIPSCO is proposing to increase the fixed charge component of Rates 111 (Residential Service), 115 (Multi-Family Service), 121 (General Service – Small), and 125 (General Service – Large) so that NIPSCO recovers a greater percentage of its fixed customer expenses through fixed customer charges because fixed gas distribution and customer expenses are incurred regardless of the customer's level of consumption. Mr. Shambo explained that a straight-fixed variable ("SFV") rate design is one in which all fixed costs are recovered through fixed charges and variable costs are recovered through variable charges, and he noted that SFV rates provide a gas customer with two transparent and accurate price signals. The first price signal is the fixed charge, which communicates to the customer the leveled monthly cost to have access to a utility's gas distribution system. The second price signal is the volumetric rate, which communicates to the customer the incremental cost to NIPSCO of supplying a single unit of the gas commodity.

Mr. Shambo testified NIPSCO's current residential fixed monthly charge is $11.00, as established in the 2010 Rate Order, and that the total monthly fixed cost of servicing each residential customer was $22.41 according to the cost of service study supporting that case.[16] He stated the monthly fixed cost associated with providing service to each residential customer has increased to $31.08 and further exacerbated the discrepancy between fixed revenue recovery and fixed cost incurrence. Mr. Shambo testified that in its 2010 Rate Order, the Commission authorized NIPSCO to increase the fixed charges it recovers through the fixed residential customer charge from $6.36 to $11.00, or 73%. In this filing, NIPSCO is proposing to increase the customer charge

[16] Verified Direct Testimony of Ronald J. Amen filed May 3, 2010, in Cause No. 43894, page 65.

from \$11.00 to \$19.50, or 77%. He stated that independent of other changes in costs reflected in the case, the fixed residential customer charge would increase from \$11.00 to \$19.50. The volumetric charge would be designed to recover the \$8.50 increase in customer charge less fixed costs from the average customer.

Mr. Shambo provided background on NIPSCO's depreciation rates. He stated that NIPSCO's depreciation rates set by the Commission's October 26, 1988 Order in Cause No. 38380 generally reflected a different system, and depreciation rates are determined at points in time based upon the system information at that time. *N. Indiana Pub. Serv. Co.,* Cause No. 38380, 1988 WL 391323 (IURC Oct. 26, 1988).

Ultimately, the life characteristics and resulting depreciation rates from the 1988 rate case produced recovery patterns that were more aggressive than what we know today. He stated the depreciation credit established in the 2010 Rate Case appropriately addressed the issue at that point in time. He testified in this filing it is appropriate to adjust and increase the depreciation expense to reflect new plant additions, increases in useful lives of its assets, and changes in net salvage. He stated the increase in NIPSCO's annual revenue requirement associated with depreciation will make up \$63.6 million of the increase requested, or 44%.

Mr. Shambo provided a summary of the changes NIPSCO is proposing to its transportation rates. He explained that NIPSCO is proposing to add a demand charge to both of its general and high-volume transportation rates. He explained that the addition of a demand charge to these rates serves to allocate fixed costs to NIPSCO's largest customers in accordance with the way that these customers use NIPSCO's system. He noted that this arrangement is beneficial to customers because it permits the fixed costs for the transportation classes to be allocated in a way that reduces the intra-class subsidies between high and low load factor customers.

Mr. Shambo provided a summary of NIPSCO's proposal to add Rider 189 – Pipeline Burner Tip Balancing Rider. He explained that the rider would be applicable to NIPSCO's large transportation rate, Rate 128, and was intended to address the specific requirements of large volume transportation customers with high variations in daily load for which NIPSCO would be unable to efficiently provide intra-day balancing without the potential for adverse impact on the operation of NIPSCO's gas system. He explained that this new rider provides such customers with the ability to obtain balancing service directly from a designated pipeline. He noted the new rider is an optional service available to Rate 128 Category A customers, but may be required in the event NIPSCO is unable to balance the customer's load under traditional methods.

Mr. Shambo testified the Commission should determine NIPSCO's Authorized Gas NOI by multiplying the fair value of NIPSCO's rate base by a fair return. He stated that NIPSCO developed its fair value rate base of ~\$2.4 billion by taking a weighted average of the following: (i) the Replacement Cost New Less Depreciation value of its gas utility assets (~\$3.45 billion) plus its TDSIC Regulatory Asset, materials and supplies, and gas stored underground (~\$115 million); and (ii) the original cost less depreciation ("Original Cost") of NIPSCO's utility property (~\$1.48 billion).

Mr. Shambo testified that NIPSCO proposes \$2,442,131,404 as the fair value of its assets and requests a fair return determination of approximately \$142.4 million, which is equal to the fair rate of return of 5.83% multiplied by NIPSCO's fair value rate base of ~$2.4 billion. He proposed that the Commission use this fair return in the earnings test used in NIPSCO's quarterly gas cost adjustment ("GCA") proceedings.

Mr. Shambo testified NIPSCO's proposed rates are not based upon a fair rate of return but rather NIPSCO's proposed rates are based on a more conservative NOI of $99.9 million, which is equal to NIPSCO Witness Rea's weighted cost of capital calculation of 6.74% multiplied by the original cost rate base of $1.48 billion. He explained that the primary reason that NIPSCO proposes a return that is substantially less than the fair return based on the fair value of its rate base is the desire to make changes to customer rates on a gradual basis. He stated NIPSCO is seeking a number of changes that will impact customer rates in this proceeding, including certain changes in rate design intended to move closer to actual fixed-variable cost incurrence, but he noted NIPSCO is asking the Commission to allow the Company an opportunity to earn a return consistent with a fair return on its fair value rate base.

Mr. Shambo testified NIPSCO is requesting an authorized NOI greater than what its proposed rates will produce, and that NOI will do the following: (i) give investors the opportunity to earn a fair return on the fair value of the capital they have invested; and (ii) give customers the benefit of lower rates based on original cost. He stated that at the rates proposed in this proceeding, NIPSCO's investors will not be able to earn a fair return on the fair value of their investment. It is only through growth in customer base or customer demand that investors will have the opportunity to earn this fair return. He explained that if the Commission does not set NIPSCO's authorized NOI at an amount necessary to provide investors the opportunity to earn a fair return, NIPSCO might have to refund to its customers earnings that the investors should be entitled to retain. He testified that this proposal provides NIPSCO an opportunity to earn a fair return on the fair value of its investment to the extent NIPSCO is not afforded an opportunity to timely recover its costs through other mechanisms. He stated NIPSCO's customers have the right to enjoy just and reasonable rates and investors have the right to the opportunity to earn a fair return on the fair value of their investment. He testified that NIPSCO's request to use original cost ratemaking to set base rates and to use a fair value return to determine authorized NOI reasonably balances these rights in this filing.

Mr. Shambo testified NIPSCO is not proposing any changes to its alternative regulatory programs in this case. He stated that in its 2010 Rate Order, the Commission approved the parties' agreement that the margins associated with NIPSCO's ARP program would be included in the GCA NOI earnings test pursuant to Ind. Code §§ 8-1-2-42(g)(3)(C) and 8-1-2-42.3 except for the following: (i) NIPSCO's Gas Cost Incentive Mechanism ("GCIM"), Capacity Release, and Optional Storage Service Rider (Rider 482A), which would be treated as below-the-line, but will continue to be shared with customers through the GCA as provided in the ARP program; (ii) NIPSCO's DependaBill program; and (iii) NIPSCO's Price Protection Service. He testified NIPSCO's proposed treatment of NIPSCO's ARP program in this case is consistent with the 2010 Rate Order. Mr. Shambo sponsored: (i) Adjustment REV 2-18R, which decreases the Forward Test Year retail gas operating revenues in the amount of $19,837,283 to remove ARP program (GCIM, Capacity Release, Optional Storage Service, DependaBill program, and Price Protection Service) revenues; and (ii) Adjustment COGS 2-18R, which decreases Forward Test Year cost of goods sold in the amount of $14,137,342 to remove ARP program.

Mr. Shambo provided a summary of NIPSCO's Gas TDSIC Plan. He stated that NIPSCO's Gas TDSIC Plan runs for the period January 1, 2014 through December 31, 2020. In this Cause, NIPSCO is proposing to include the approved TDSIC assets that will be in-service at the end of the Forward Test Year in rate base. Costs associated with approved TDSIC assets from the Gas TDSIC Plan that have not been placed in-service at the end of the Forward Test Year will continue to be recovered through NIPSCO's TDSIC tracker filings (Cause No. 44403-TDSIC-X). He also stated that NIPSCO anticipates requesting in a separate proceeding approval of a new gas seven-year TDSIC plan, proposing transmission, distribution, and storage system improvement projects for a new seven-year term beginning in January of 2019.

Mr. Shambo provided a summary of NIPSCO's gas DSM and EE program. He stated the Commission approved NIPSCO's current gas DSM and EE program in December 2015 and authorized the program to be implemented until the end of 2018. NIPSCO will be requesting approval of a new DSM and EE program to be effective for calendar years 2019 – 2021 before the Commission issues an Order in this Cause. He indicated that in that proceeding, NIPSCO would be seeking authority to recover the margins it loses as a result of its gas DSM and EE programs.

Mr. Shambo testified NIPSCO also anticipates requesting approval to implement a rate adjustment mechanism that will allow NIPSCO to recover its federally mandated costs that exceed those recovered in base rates. He stated that operators of underground gas facilities like NIPSCO are subject to increasingly stringent regulatory requirements associated with pipeline safety promulgated by the Pipeline and Hazardous Materials Safety Administration ("PHMSA"). A number of high profile pipeline and storage incidents have prompted regulatory initiatives at PHMSA, several of which are still pending. He stated the safety of NIPSCO's customers and communities and compliance with pipeline safety requirements are of paramount importance to NIPSCO. He indicated that while some of the costs associated with these federally mandated regulatory requirements are reflected in the revenue requirement identified in this case, other costs of compliance with newly promulgated rules and pending rulemakings were not fully developed in time for inclusion in this case.

C. **June M. Konold.** Ms. Konold, Vice President of Regulatory Strategy and Support with NCSC, presented the results of NIPSCO's gas operations for the Historic Base Period beginning January 1, 2016 and ending December 31, 2016 and for the Forward Test Year beginning January 1, 2018 and ending December 31, 2018, adjusted on a pro forma basis for the normalization and annualizing of certain amounts included in these periods. Ms. Konold quantified the amount by which retail gas revenues should be increased so that NIPSCO may have the opportunity to earn a fair and reasonable return.

Ms. Konold testified NIPSCO's proposed rates are based on a Forward Test Year, consistent with Ind. Code 8-1-2-42.7. She stated NIPSCO has provided information for the Historic Base Period, as well as for the period January 1, 2017 through December 31, 2017 (the "2017 Budget Period"), for comparison purposes. She stated NIPSCO has proposed both ratemaking and forward looking adjustments to the Historic Base Period and Forward Test Year to support the forecasted amounts for the Forward Test Year as well as the normalization and annualizing of these test periods. She stated NIPSCO elected to proceed under the Commission's final rules on the MSFRs (170 IAC 1-5-1 through 16) and followed Appendix B to the Commission's Recommended Best Practices for Rate Cases Submitted under Ind. Code § 8-1-2-

42.7 (GAO 2013-5) as it relates to the MSFRs and the supporting documentation for changes between the Historic Base Period and the Forward Test Year.

Ms. Konold testified that NIPSCO proposes retail gas rates designed to recover through base rates the gross retail gas revenue in the amount of $775,629,855, an increase of $143,471,798 over the forecasted Forward Test Year pro forma results based on current rates. She also noted that rates based upon this level of annual revenue requirements would provide NIPSCO with an opportunity to earn annual jurisdictional NOI of $99,941,966. She stated NIPSCO's proposed rates have been calculated using NIPSCO's requested return on the Forward Test Year original cost rate base and capital structure. She stated NIPSCO is proposing to implement the requested rate relief in this proceeding in a two-step process to reasonably reflect the utility property that is used and useful at the time rates are placed into effect.

Ms. Konold described the attachments supporting NIPSCO's revenue requirement as follows: Pet. Ex. 3, Attach. 3-A at 1 and 2 is NIPSCO's Statement of Operating Income for the Forward Test Year shown on a forecasted basis, with pro forma adjustments to arrive at current and proposed rates; Pet. Ex. 3, Attach. 3-A, at 3 shows the calculation of the required NOI. Pet. Ex. 3, Attach. 3-B includes the major components of the revenue requirement (e.g. operating revenue, gas costs, and O&M expense, etc.) with detail for each major "subcomponent." Pet. Ex. 3, Attach. 3-C shows, by subcomponent, the changes between the Historic Base Period and the Forward Test Year including a listing of each normalization, budget and ratemaking adjustment. Pet. Ex. 3, Attach. 3-D represents the adjustments included in Attach. 3-C. Finally, Pet. Ex. 17 includes work papers supporting each adjustment.

Ms. Konold described the development of the revenue requirements for the Forward Test Year. She stated the proposed revenue requirement was based on NIPSCO's 2018 budget adjusted for ratemaking adjustments. She noted that for each revenue requirement component, NIPSCO provided support and models to describe the changes from the 2016 actual results to the 2018 forecasted amounts which are used for ratemaking purposes. This documentation supports the proposed 2016 and 2018 normalization and ratemaking adjustments as well as, where applicable, the 2017 and 2018 budget adjustments.

Ms. Konold provided explanations for each of NIPSCO's proposed pro forma adjustments to revenue, cost of gas sold, operating expenses, depreciation and amortization expense, and tax expense as part of her direct testimony. She also sponsored Pet. Ex. 3, Attach. 3-E, Rate base Sched. 1 quantifying NIPSCO's December 31, 2018, forecasted net original cost rate base. The amounts in Pet. Ex. 3, Sched. RB-1 represent the forecasted utility plant balances for both gas and common assets. The 2017 and 2018 values were calculated based on a series of assumptions including forecasted capital expenditures and retirements. The amounts in Pet. Ex. 3, Sched. RB-2 represent the forecasted accumulated depreciation, with 2017 and 2018 values calculated based on a series of assumptions including forecasted capital expenditures, in-service timing, forecasted retirements, and cost of removal. The amounts in Pet. Ex. 3, Sched. RB-3 represent a regulatory asset of $20,763,169 related to TDSIC costs that reflect forecasted amounts deferred as of December 31, 2018. The amounts in Pet. Ex. 3, Sched. RB-4 represent actual and forecasted balances of NIPSCO's materials and supplies. The amounts in Pet. Ex. 3, Sched. RB-5 represent the actual and forecasted 13-month average balance of NIPSCO's Current Underground Storage. No adjustments were made to the balance of NIPSCO's Non-Current Underground Storage.

Ms. Konold supported NIPSCO's calculation of the 2017 and 2018 WACC shown on Pet. Ex. 3, Attach. 3-F, Cap Sched. 1. She explained that "PPA" represents the difference between the forecasted cumulative amount of cash contributions to NIPSCO's pension trust fund and the forecasted cumulative amount of pension expense that will be recorded on NIPSCO's books and records in accordance with Generally Accepted Accounting Principles ("GAAP"). The pension trust fund contributions that are in excess of historical amounts charged to operating expense were included in the determination of revenue requirements in past rate cases and recovered from NIPSCO's gas utility customers. These amounts represent investor capital contributions. She explained that NIPSCO's retail gas customers benefit from investor capital contributions because earnings on PPAs serve to reduce pension expense. She also explained that NIPSCO's pension funding strategy is the following: (1) in part, mandated by federal regulations; and (2) an ordinary cost of doing business. The strategy results in costs prudently incurred on behalf of customers. For these reasons, and in order to not understate the cost of service, costs associated with NIPSCO's pension funding strategy were included in the determination of the jurisdictional revenue requirement in this proceeding. She stated that in order to capture the costs associated with this program, NIPSCO included the balance of the PPA as a component of NIPSCO's overall WACC.

Ms. Konold provided explanations for each of NIPSCO's proposed pro forma adjustments to its proposed capital structure in her direct testimony.

Ms. Konold stated that NIPSCO's accounting and financial reporting policies and procedures conform to GAAP, rules of the Securities and Exchange Commission ("SEC"), and the Federal Energy Regulatory Commission ("FERC") Uniform System of Accounts. In addition, she explained that NIPSCO's (and NiSource's) financial books and records are formally audited by its outside auditors, and these outside audits are supplemented by internal audits. She also discussed the various controls NIPSCO utilizes to ensure the accuracy of its accounting books and records and financial statements. She testified NIPSCO's books and records are also subject to audit by the OUCC, the Commission, and FERC.

Ms. Konold testified that common costs are allocated between electric and gas using common allocation ratios that measure the cost causation relationship between the electric and gas functions for such costs. She explained that such ratios are updated twice each year to reflect the most current information. She also testified that NCSC costs are allocated between electric and gas based upon allocators developed specifically for this purpose.

D. Clifton Scott. Mr. Scott, State Finance Director with NIPSCO, explained and supported the following: (i) the financial planning and budgeting processes used at NIPSCO; (ii) the 2018 financial plan and budget, which is the underlying basis for the rate request in this proceeding; (iii) the 2017 and 2018 budget adjustments; and (iv) the 2016 normalization adjustment. He summarized the processes used at NiSource and NIPSCO for development of capital and O&M budgets, as well as longer-term financial plans. He explained the rigorous process that is used at NiSource and NIPSCO to develop robust and accurate budgets and financial plans, including engaging leadership and operations personnel and prioritizing safety, reliability, customer service, and compliance. He stated NIPSCO's budgeting process produces budgets that are reliable forecasts of future capital and O&M needs and expenditures.

Mr. Scott testified that a financial plan is a forecast of a business entity's revenues, expenses, and capital expenditures for a future period. It is developed to enable the entity to assess its financial needs and goals and how to achieve them. He stated the financial planning process at NIPSCO currently involves creating two financial plans each year: an annual two-year financial plan with monthly detail ("Annual Financial Plan"), and a separate, long-range plan with five years of detail. He testified that NIPSCO's 2017-2018 Annual Financial Plan was finalized in January 2017 (the "NIPSCO 2017-2018 Financial Plan"), and it was utilized as the basis for the forecast in this proceeding.

Mr. Scott described NIPSCO's budgeting and financial planning process for its gas utility. He explained the process is top down because total spend amounts for capital and O&M are agreed upon by a leadership team in NIPSCO management, NiSource Finance, and Capital Execution. The process is also grass roots because once totals are known, operations develop work plans to identify the resources (labor, materials, and contractors, etc.) needed to complete the work for the year. He testified that revenue assumptions are combined with NIPSCO's O&M and capital budgets to arrive at an annual financial plan for NIPSCO prepared in good faith utilizing the best information that was reasonably available at that time and that no changes are made. He explained that a reprioritization process is used to address additional information that becomes available after the completion of the annual financial plan that may result in budget reprioritization or the need for incremental funding. He noted that in the event that incremental funding is required, the NIPSCO management team must present its need to the NiSource Executive Governance Committee, which is responsible for evaluating the merits of the request and granting incremental funding if deemed necessary. Although incremental funding may be granted, NIPSCO continues to measure its results against the unadjusted annual financial plan.

Mr. Scott testified the O&M budgeting methodology results in an accurate estimate of expenses to be incurred during 2018. He stated that NIPSCO has experienced a variance of less than 6%, as compared to the gas utility's approved O&M budget over the last five years. NIPSCO demonstrates a high level of historical O&M budgeting accuracy in spite of an environment influenced by external factors that are outside of its control such as weather. He concluded that these results should provide a high level of confidence and reliability as to the accuracy of the O&M expenses included in NIPSCO's 2018 O&M budget.

Mr. Scott also described the capital planning process for the gas utility as a collaborative process among NIPSCO's President, other members of NIPSCO management, and the NiSource Finance and Capital Execution teams. NIPSCO management, along with Capital Execution, are primarily responsible for identifying the capital investment needs for public safety and reliability, compliance requirements, and customer service levels, and for identifying capital plan recommendations. These recommendations are reviewed with NiSource Finance to ensure affordability. The recommendation of these groups is then reviewed with NIPSCO's President. The annual financial plan establishes the budget for the year, and any reallocations to the budget are approved according to the NiSource Capital Governance Policy.

Mr. Scott testified the capital budgeting methodology results in an accurate estimate of capital to be expended during 2018. He stated NIPSCO has experienced a variance of just 7%, compared to the gas utility's approved capital budget over the last five years. He explained that the main drivers were strong new business growth and additional public improvement demand related to external factors that are largely outside of NIPSCO's control. If those drivers were removed, the variance would be close to 1%. He testified that these results should provide a high level of confidence as to the accuracy of the capital expenses included in the NIPSCO 2017-2018 Financial Plan.

Mr. Scott described how revenues are forecasted for the NIPSCO budget. He explained that revenues are forecasted for the NIPSCO annual financial plan as follows: (i) the Demand Forecasting department aggregates all volumes/customer count and distributes the demand forecast; (ii) the Hammond Operations department provides price estimates for both the cost of goods sold and gas in storage; (iii) the Financial Planning department allocates the cost of goods sold to the revenue classes based on volume; (iv) the Financial Planning department enters the volumes in pricing models, which allocate volumes to specific tariffs and rates based on a 12-month look-back; and (v) the Financial Planning department applies the tariff rates to determine the margins. He testified that the revenue forecasting methodology results in an accurate estimate of revenues to be achieved during 2018, with the caveat that the revenue forecast presented in this case does not reflect proposed or anticipated revenues resulting from this proceeding.

Mr. Scott testified the NIPSCO 2017-2018 Financial Plan was prepared in accordance with the processes he described and consistent with the authority to issue debt that NIPSCO received in Cause No. 44796.[17] *N. Indiana Pub. Serv. Co.,* Cause No. 44796, 2016 WL 7046627 (IURC Nov. 30, 2016).

Mr. Scott testified that the NIPSCO 2018 forecasted consolidated income statement and consolidated balance sheet were prepared in accordance with NIPSCO's normal forecasting processes and based on the consolidation of data provided by business units and various corporate departments. The forecast is fully integrated between the income statement, balance sheet, and statement of cash flows. He testified that the NIPSCO forecasted consolidated statement of cash flows is a function of the items reflected in the forecasted balance sheet. Cash needs dictate the extent of debt and equity that is necessary to operate the business, given the timing of cash inflows and outflows. He testified the forecasted consolidated balance sheet is based on the capital expenditures, operating costs, and capital structure reasonably necessary for the going forward operation of NIPSCO.

Mr. Scott explained that the majority of NIPSCO's revenues come from retail sales, with other revenue components including: (i) ARP revenues; (ii) TDSIC revenues; (iii) transportation revenues; and (iv) other revenues. Mr. Scott testified that under current rates, NIPSCO's revenues in 2018 are forecasted to be $649,920,818 based on the major assumptions used for customer usage volumes, cost of gas sold, and approved retail gas utility tariff rates. Pet. Ex. 3, Attach. 3-B, Rev. Sch. 1. NIPSCO provided information, including calculations, supporting the Revenue Budget Adjustments between the Historic Base Period and the Forward Test Year.

Mr. Scott described the major components of NIPSCO's cost of gas sold as gas procured for retail sales, ARP gas costs, transportation gas cost, and interdepartmental sales. Mr. Scott testified NIPSCO's cost of gas sold in 2018 is forecast to be $328,857,191. He stated the major

[17] The NIPSCO 2017-2018 Financial Plan included the issuance of approximately $40 million of debt in June 2017, approximately $160 million of debt in August 2017, and approximately $300 million of debt in June 2018. This totals the $500 million of debt authorized in Cause No. 44796.

assumptions used in the development of the forecasted 2018 costs of gas sold were the forecasted natural gas usage, the forecasted amounts of natural gas in storage (net of purchases and transportation for injection/withdrawal activity), and the Weighted Average Cost of Gas ("WACOG") of the amount of natural gas in storage. Since the biggest driver of cost of gas sold is the commodity itself, he explained that the cost of the gas purchased is based upon the forward curve. NIPSCO provided information, including calculations, supporting the Cost of Gas Sold Budget Adjustments between the Historic Base Period and the Forward Test Year.

Mr. Scott described the major components of NIPSCO's O&M expenses as transmission, distribution, storage, operating and maintenance expenses, customer account expenses, and administrative and general expenses. Mr. Scott testified NIPSCO's O&M expenses for 2018 are forecast to be $199,338,002. He stated the major assumptions used in the development of the forecasted 2018 O&M expenses were as follows: (i) a labor expense increase (3% for non-union employees, and 3.5% for union employees); and (ii) a 2% overall O&M expense increase (such that the labor increase must fit within the 2% overall O&M expense increase). Other assumptions included the results of pension and other post-employment benefits ("OPEB") actuarial reports. NIPSCO provided information, including calculations, supporting the O&M Budget Adjustments between the Historic Base Period and the Forward Test Year.

Mr. Scott described the major components of NIPSCO's tax expenses other than income tax to be property taxes, payroll taxes, public utility fees, and Indiana Utility Receipts Taxes ("URT"). Mr. Scott testified NIPSCO's tax expenses, other than income taxes, for 2018 is forecast to be $26,618,273. Pet. Ex. 3, Attach. 3-B, OTX Sch. 1. He stated the major assumptions used for development of the forecasted 2018 tax expenses, other than income taxes, include forecasted amounts for: assessed property value for property tax, payroll expense for payroll taxes, and gross revenues for URT. NIPSCO provided information, including calculations, supporting the tax expenses other than income budget adjustments between the Historic Base Period and the Forward Test Year.

Mr. Scott stated the major components used in the development of the forecasted 2018 capital expenditures are as follows: (i) growth (also referred to as new business); (ii) TDSIC tracker; (iii) maintenance betterment (capacity or compliance); (iv) replacement (age and condition); (iv) public improvement (mandatory relocation); and (v) corporate (Shared Services). Mr. Scott testified NIPSCO's capital expenditures in 2018 is forecast to be $255,358,092. He stated the major assumptions used for development of the forecasted 2018 capital expenditures were focused on TDSIC work, maintenance for transmission and distribution that is not part of TDSIC, growth and new business including rural extensions covered under TDSIC, and indirect costs. NIPSCO provided information, including calculations, supporting the capital expenditures adjustments between the Historic Base Period and the Forward Test Year.

Mr. Scott explained that the major components of NIPSCO's other plant balances consist of utility plant, accumulated depreciation and amortization, TDSIC regulatory asset, materials and supplies, and gas stored underground. Mr. Scott testified NIPSCO's other plant balances in 2018 are forecast to be $115,463,633 based on major assumptions concerning the following: (i) gas inventory in storage; (ii) amount of TDSIC deferrals; and (iii) balance of materials and supplies needed to support the business. NIPSCO provided information, including calculations, supporting the other plant balances adjustments between the Historic Base Period and the Forward Test Year.

Mr. Scott also provided a summary of the remaining variances between the budget or forecast for 2018 as compared to the budget or forecast for 2017 and 2016 normalized in Pet. Ex. 4, Attach. 4-F. He explained NIPSCO's proposed Adjustment OM 2U-16 on Pet. Ex. 3, Attach. 3-D. The adjustment decreases Historic Base Period O&M expenses by $1,102,328 to normalize the 12 months ended December 31, 2016 Gas Operations O&M expenses to remove one-time items that are not budgeted to recur during the twelve months ending December 31, 2017 and December 31, 2018.

E. **Albert A. Stone.** Mr. Stone, Vice President and General Manager with NIPSCO, sponsored adjustments to NIPSCO's Historic Base Period and Forward Test Year to reflect the ongoing level of O&M activity. He also addressed the types of projects addressed by the portion of NIPSCO's capital budget for which his team is responsible for executing.

Mr. Stone provided an overview of NIPSCO's gas operations and maintenance organization, its gas storage organization, and its damage prevention organization. Mr. Stone described the value NIPSCO's customers receive from operational efficiencies. NIPSCO has maintained a focus on operational efficiency and a philosophy of prudency with expenses. As a result of the quality of its gas infrastructure, NIPSCO does not incur significant expense responding to and repairing leaks on its mains and service lines. NIPSCO captures efficiencies by virtue of being a combination gas and electric utility in several areas allowing many tasks (such as line locating, meter reading, and service installations and activations) to be completed jointly for gas and electric and appropriately sharing the costs between both utilities.

Mr. Stone testified the greatest threat to the integrity of NIPSCO's gas systems is the risk of third-party damages during excavations, typically for non-NIPSCO related work. Mr. Stone supported gas infrastructure locating expenses. He testified the Historic Base Period is not a good representation of locate costs going forward. He stated NIPSCO projects that locate ticket volume will increase to 465,000 for 2017 and to 513,000 for the Forward Test Year. He stated that while it is difficult to precisely identify the cause for the increase in ticket volume, the following are certainly factors driving the increase: (i) improved economic conditions since 2008 have driven an increase in construction activity; (ii) increased public awareness has led to an upward trend in the number of locate tickets received from homeowners and small excavators; and (iii) finally, impositions of civil penalties for excavators since the amendment of Indiana's Dig Law in 2009 have increased awareness in the excavator community of the need for timely locate requests in conjunction with their projects.

Mr. Stone explained that NIPSCO's underground facility locates are performed under two new contracts with locate contractors. The contracts became effective on March 8, 2017, and the contracts provide a number of improvements over the services provided under NIPSCO's previous contract. However, the cost of each locate is higher now than under the previous contract executed in 2009. Mr. Stone's testimony explained the $3,316,412 increase in O&M expense for line locate expense, as shown on Adjustment OM 2A on Pet. Ex. 3, Attach. 3-D.

Mr. Stone also supported right-of-way clearing expenses. He testified right-of-way clearing is important to keep rights-of-way clear from vegetation that could impede access in the event that repairs or replacement prove necessary. It also reduces the likelihood that vegetation roots could interfere with the facilities or make maintenance and repair difficult in the future. He testified that clearance is important wherever transmission and distribution lines run, but clearance is particularly critical in wooded areas outside of public road rights-of-way. Mr. Stone's testimony explained NIPSCO's proposed adjustment to increase O&M expenses for right-of-way clearing expenses in the amount of $1,376,369. See Pet. Ex. 3, Attach. 3-C and 3-D, Adjust. OM 2B-17 and OM 2B-18.

Mr. Stone testified a "cross-bore" occurs when a utility line is accidently bored through a sewer or septic line. He explained that while contemporary horizontal boring practices and updated damage prevention laws generally reduce the likelihood of new cross-bores, older techniques and technology were not always as safe. Cross-bores were created without the knowledge of installation crews because the boring unit could pass through a sewer or septic line without producing any telltale signs. He testified that cross-bores present a very dangerous situation. If the sewer or septic line becomes clogged and must be cleaned out, the equipment used to root out the clog can damage or rupture the cross-bored gas line and cause leakage of gas into the sewer or septic system and the attached residence or business. He explained that once identified, remediation is comparatively simple, but that the more difficult task is identifying locations where cross-bores have occurred. He noted that the frequency and location of cross-bores are highly variable and depend on a number of factors, including the age of the gas and sewer systems and the way specific areas were developed over time. Technology has been developed to permit remote cameras to be inserted into sewer lines to identify the presence of obstructions. Mr. Stone's testimony explained NIPSCO's proposed adjustment to increase O&M expenses for legacy cross-bore expenses in the amount of $806,200. Pet. Ex. 3, Attach 3-C and 3-D, Adjust. OM 2F.

Mr. Stone's direct testimony also addressed "abnormal operating conditions" ("AOC") expenses as defined in PHMSA's performance standards, 49 Code of Federal Regulations ("C.F.R.") §§ 192.803 and 195.503. He explained that "AOC" means a condition identified by the operator that may indicate a malfunction of a component or deviation from normal operations that may do the following: (i) indicate a condition exceeding design limits; or (ii) result in a hazard(s) to persons, property, or the environment. He cited examples of AOCs including the following: (i) service risers, meters, or service lines in inappropriate locations that require relocation; and (ii) loops and risers that require painting, replacement, or a rebuild to protect them from atmospheric corrosion. Mr. Stone explained that these conditions are frequently identified during leak surveys. Mr. Stone's testimony explained NIPSCO's proposed Adjustment OM 2J to increase O&M expenses for a new AOC program in the amount of $2,300,000. Pet. Ex. 3, Attach. 3-D, Adjust. OM 2J.

Mr. Stone testified that the large assets on NIPSCO's system include Points of Delivery ("PODs") where gas is delivered to the NIPSCO system from interstate pipelines, regulator and large capacity meter stations, and equipment associated with NIPSCO's Liquefied Natural Gas ("LNG") vaporizer units and Royal Center Underground Storage ("RCUGS") wells. He said that NIPSCO has 37 PODs associated with the seven interstate pipeline systems serving it. NIPSCO has more than 800 large capacity meter and regulator stations and a variety of equipment associated with its LNG and RCUGS facilities with equipment above ground and exposed to the elements where they can corrode and degrade. They must be continually evaluated and remediated to preserve their long term integrity. He explained that remediation involves the following: (i) checking for the presence of lead-based paint and removing the paint, if required; (ii) preparing site and taping; sand blasting exposed piping; applying epoxy coating; (iii) applying a polyurethane coating; (iv) installing an appropriate air to soil interface; and (v) cleaning up. Mr. Stone's testimony explained NIPSCO's proposed Adjustment OM 2L to increase O&M expenses for a new painting program to comply with Department of Transportation ("DOT") Part 192, to extend the life, and to enhance integrity of various gas system assets in the amount of $420,000. This is a new program to remediate atmospheric corrosion on large gas assets to comply with 49 C.F.R. §§ 192.479 and 192.481. Pet. Ex. 3, Attach. 3-D, Adjust. OM 2L.

Mr. Stone supported an ongoing system integrity data integration project that is a process of capturing data from NIPSCO's analog system records and converting that data into a digital form that can be used in a variety of ways for a variety of purposes. He explained that many of NIPSCO's distribution system records were historically maintained on large bound volumes of linen maps onto which attribute, location, and maintenance records were written over the years. That work is continuing under NIPSCO's Gas TDSIC Plan. Mr. Stone testified that costs up to the approved $12.2 million budget will continue to be tracked through NIPSCO's gas TDSIC tracker. The portion of the project addressed through the Gas TDSIC Plan has narrowed in scope since its inception, and it no longer includes the capture of data from NIPSCO's paper service cards for integration into NIPSCO's Geographic Information System ("GIS") system and other digital platforms. Mr. Stone's testimony explained NIPSCO's proposed Adjustment OM 2N to increase O&M expenses for ongoing linens costs not trackable through TDSIC in the amount of $1,569,027. Pet. Ex. 3, Attach. 3-D, Adjust. OM 2N.

Mr. Stone also testified in support of expenses for proposed training center improvements at the NIPSCO training center located in LaPorte, Indiana (the "LaPorte Training Center"). He explained that the LaPorte Training Center is a centralized training facility consisting of 35 acres of classrooms and field simulation space. NIPSCO currently employs 32 full and part time employees that develop, provide, and document a comprehensive series of courses for both gas and electric personnel. Mr. Stone testified that a gap analysis was performed to benchmark NIPSCO's current gas training regimen against current standards of the Midwest Energy Association. It was determined that gaps exist between NIPSCO standards and both industry best practices and the common platform used across the NiSource local distribution companies ("LDCs"). There was a need to update NIPSCO's curriculum and resources. He stated the proposed improvements in the training curriculum at the LaPorte Training Center will include training to an updated Operator Qualification ("OQ") platform in common with all of the NiSource LDCs. It also includes updating existing gas training programs to be consistent with NIPSCO's current gas standards adopted in 2017 to not only be consistent with the applicable current regulatory requirements, but also to be consistent across the NiSource footprint. Mr. Stone's testimony explained NIPSCO's proposed Adjustment OM 2P to increase O&M expenses for proposed LaPorte Training Center improvements in the amount of $1,000,000. Pet. Ex. 3, Attach. 3-D, Adjust. OM 2P.

Mr. Stone explained that carrier pipe casings are steel pipes that were historically used to protect distribution pipe when it was installed at a crossing site such as a bridge over a stream or other obstacle. Mr. Stone supported expenses for a new test station casing program. He testified that carrier pipe casings are no longer commonly used because they have proven over time to trap moisture inside, posing a risk of increased corrosion on the enclosed steel pipe. He stated that in evaluating the options to address the integrity risk associated with these crossings, it was determined that the cost of installing test stations was far lower than the cost of either removing the steel casings or replacing each crossing with a new, directionally bored crossing. This will allow NIPSCO to monitor these casings and evaluate what, if any, corrective action is required. Mr. Stone's testimony explained NIPSCO's proposed Adjustment OM 2R to increase O&M expenses for a new test station casing program in the amount of $350,000. Pet. Ex. 3, Attach. 3-D, Adjust. OM 2R.

Mr. Stone testified that while his organization is largely engaged in O&M work involved with NIPSCO's gas systems, it also undertakes a wide variety of non-TDSIC capital projects associated with the operation and maintenance of NIPSCO's system. These projects fall into four non-TDSIC capital budget categories as follows: (i) "Minor Main" is the replacement of short sections of leaking main identified through leak surveys and/or customer requested odor investigations (Grade 1 and 2 leaks); (ii) "Regulator and Meter" is the replacement of regulators and meters with new fixtures of the same size because of leakage or atmospheric corrosion; (iii) "Service Line" is the replacement of services and/or service risers identified through leak surveys and/or customer requested odor investigations (Grade 1 and 2 leaks); and (iv) "Maintenance Capital – General" is the replacement of other types of system equipment assets that have failed that are not included in any of NIPSCO's other TDSIC projects. He testified budgets for these and the other non-TDSIC capital expenditure categories (Public Improvement and non-rural New Business) are developed by NIPSCO's Engineering Department and are among the inputs into the budget forecasting process.

F. **James S. Roberts.** Mr. Roberts, Director of Pipeline Safety with NCSC, described NIPSCO's pipeline safety programs and processes and supported adjustments to reflect changes in costs associated with those programs. He also described the components of those programs that will be included in a subsequent proceeding seeking approval to implement a rate adjustment mechanism that will allow NIPSCO to recover its federally mandated costs relating to these components.

Mr. Roberts provided an overview of the pipeline safety regulations that apply to NIPSCO's pipeline safety programs and processes, including minimum pipeline safety standards published in the 49 C.F.R. § 192 (the "Code"). He stated these mandated rules, and the many amendments and additions that have occurred over 47 years, have defined the minimum standards for the safe construction, operation, and maintenance of natural gas systems. He explained that for much of those 47 years, the rules and amendments have been very prescriptive regarding actions that operators must take, how frequently they must conduct those actions, and the types of documentation and retention of documents related to those activities. He explained that Indiana specifically requires gas utilities to adhere to requirements regarding the following: corrosion control, pressure testing, pressure rating, and operations and maintenance of gas facilities. He also discussed that a number of the amendments and additions to the Code have included requiring operators to create mandated programs, directly affecting aspects of pipeline and public safety. Some of the more established mandated programs include the following: (i) Damage Prevention Program (49 C.F.R. § 192.614); (ii) Operator Qualification Program (49 C.F.R. § 192 Subpart N); (iii) Public Awareness Program (49 C.F.R. § 192.616); (iv) Emergency Plans (49 C.F.R. § 192.615); and (v) Control Room Management (49 C.F.R. § 192.631).

Mr. Roberts testified that while the majority of the Code is prescriptive, portions of the Code mandate operators to establish programs that are risk-based. For instance, 49 C.F.R. 192

Subpart O mandates operators to create a Transmission Integrity Management Program ("TIMP") covering the higher pressure transmission pipeline and corresponding systems. 49 C.F.R. 192 Subpart P mandates operators to create a Distribution Integrity Management Program ("DIMP") covering the lower pressure distribution system. Mr. Roberts explained that these programs provide a regulatory structure for the assessment of system risks, progressive implementation of solutions, and continuous improvements based upon the risks. The risk-based integrity management programs enable operators to implement pipeline safety and integrity actions specific to their systems in addition to prescriptive actions defined in the balance of the Code requirements. Mr. Roberts testified NIPSCO complies with applicable pipeline safety standards promulgated by the Commission's Pipeline Safety Division and the Federal DOT's PHMSA Office of Pipeline Safety.

Mr. Roberts testified about several initiatives proposed in this case that focus on improving pipeline safety and go beyond prescriptive minimum actions. He explained that NIPSCO has identified and is beginning to implement initiatives going beyond the minimum standards in NIPSCO's damage prevention, emergency management, and operator qualification programs to improve pipeline safety. NIPSCO is also implementing a new pipeline safety management system ("PSMS") program. Implementation of a PSMS is not required by any federal or state code at this time, but it is a recommended practice endorsed by many federal and state regulatory bodies. He noted that NIPSCO is also identifying additional initiatives driven by TIMP and DIMP, including accelerated riser replacement, cross-bore remediation programs, and making more NIPSCO transmission lines accessible for internal inspection.

Mr. Roberts also provided high level explanations of both the federal TIMP and DIMP regulatory schemes. The the intent of both schemes is to identify potential threats to systems, assess the severity of those threats with a risk analysis process, rank the risks identified, and remediate or monitor the risks as appropriate. He noted that operators address potential threats by either repairing defects, replacing pipeline sections, or implementing preventive and mitigating measures to preemptively identify changes in threats. Mr. Roberts presented testimony that described NIPSCO's TIMP and DIMP and the process of developing and implementing each.

Mr. Roberts testified that NIPSCO's Damage Prevention Risk Model combines technology with additional dedicated damage prevention personnel to help NIPSCO achieve the following: (i) identify higher risk excavations; (ii) take preventative steps beyond simply locating gas facilities for excavators; and (iii) assign risk factors to Indiana One Call tickets. He explained that a dedicated team of damage prevention personnel will be hired to execute those additional actions, including making direct contact with the excavators through e-mail, phone calls, and face-to-face pre-excavation meetings and on-site monitoring of excavations. Mr. Roberts provided testimony supporting Adjustment OM 2C to increase O&M expenses for damage prevention risk model expenses in the amount of $871,000. Pet. Ex. 3, Attach. 3-D, Adjust. OM 2C.

Mr. Roberts also supported transmission risk modeling expenses and testified that transmission risk models are used for two practical but distinct purposes within the life cycle of the development of an effective TIMP strategy. First, the transmission risk model was used for TIMP development and involved an indexing methodology to identify and to prioritize the highest risk of the transmission pipeline systems. It also monitored for pertinent changes during the remainder of the baseline assessment process. The baseline process was completed in 2010.

Second, the purpose of the transmission risk model is a more quantitative version that manages and analyzes large volumes of attribute, environment, operational, and maintenance data involving the transmission assets. It notes changes in risk in conjunction with changes in conditions of these various parameters. He noted that these systems also analyze the interactions of threats to better understand the cumulative impacts of these conditions, and he explained why NIPSCO needs to upgrade the risk assessment tools it is currently using. Mr. Roberts provided testimony supporting Adjustment OM 2D to increase O&M expenses for transmission risk modeling expenses in the amount of $300,000. Pet. Ex. 3, Attach. 3-D, Adjust. OM 2D.

Mr. Roberts supported an adjustment targeted toward shallow pipe replacements. He testified that NIPSCO identified segments of its transmission system located in tillable agricultural areas that, over years of apparent soil shifts and/or erosion, are shallower than when originally installed. He explained that as NIPSCO plans for the eventual replacement and/or lowering of these segments of pipe, it has determined that it is prudent to engage with landowners to execute agreements to compensate them for not planting crops on those rights-of-way to reduce the likelihood of damage. Mr. Roberts provided testimony supporting Adjustment OM 2E to increase O&M expenses for shallow pipe replacement expenses in the amount of $130,000. Pet. Ex. 3, Attach. 3-D, Adjust. OM 2E.

Mr. Roberts testified that NIPSCO has been pursuing improvement of its gas distribution system records through a linen mining project as part of its Gas TDSIC Plan. The linen mining project enables NIPSCO to utilize the enhanced system records in its GIS to validate current Maximum Allowable Operating Pressures ("MAOP") records through a tracing methodology based on information captured from NIPSCO's linen books. Document retention for anything installed prior to initiation of the Code in 1970 was less rigorous in the industry than it is now. Validating what records NIPSCO has and that the records align with the appropriate systems adds another quality assurance layer in the design and operation of those systems. He provided testimony supporting Adjustment OM 2H to increase O&M expenses associated with engaging vendors to assist Engineering with tracing and validating documents for the new MAOP distribution program in the amount of $500,000. Pet. Ex. 3, Attach. 3-D, Adjust. OM 2H.

Similarly, Mr. Roberts supported an adjustment for increased MAOP transmission program expenses. He testified the purposes of a MAOP transmission program are to verify that the MAOP documentation for transmission pipeline assets is traceable, verifiable, and complete and to systematically identify gaps due to data or process issues, complying with PHMSA's Advisory Bulletin 11-01 and consistent with PHMSA's pending Gas Transmission and Gas Gathering rule.[18] He explained that the continued scrutiny and enhancement of MAOP records supports the execution of NIPSCO's TIMP, regardless of when the rule becomes final. Mr. Roberts provided testimony supporting Adjustment OM 2I to increase O&M expenses for a new MAOP transmission program in the amount of $1,250,000. Pet. Ex. 3, Attach. 3-D, Adjust. OM 2I.

Mr. Roberts testified that NIPSCO's proposed Quality Assurance / Quality Control ("QA/QC") program is an auditing program that reviews actual service, construction, and maintenance work conducted in the field by front line employees and contractors. It is a critical step in the assurance that qualified people are doing their work in accordance with the Code and

[18] PHMSA Docket No. PHMSA-2011-0023.

NIPSCO's own gas standards. He explained that the QA/QC program has been piloted and is in place in affiliate NiSource companies. It utilizes seasoned subject matter experts in the Pipeline Safety and Compliance department together with an electronic application called iAuditor. Mr. Roberts provided testimony supporting Adjustment OM 2K to increase O&M expenses for a new QA/QC program with four personnel in the amount of $315,000. Pet. Ex. 3, Attach. 3-D, Adjust. OM 2K.

Mr. Roberts also submitted testimony in support of PSMS program expenses. He testified that a safety management system is a systematic approach to managing safety, including structures, policies, and procedures used to direct and control activities. Such systems have been defined and in place in other industries, especially ones with high risk and low tolerance for failures. He testified that NIPSCO reviewed the results that some of these other industries have seen over time by implementing safety management systems. NIPSCO sees the benefit of a strong systemic approach to improving pipeline safety. He noted that NiSource is participating in an American Gas Association ("AGA") pilot program with 11 other gas operators across the country who are committed to learning about and implementing a PSMS in their organizations. He testified that PHMSA's Office of Pipeline Safety and the National Transportation Safety Board have actively encouraged operators at public workshops and industry conferences to voluntarily implement a PSMS program. Mr. Roberts provided testimony supporting Adjustment OM 2M to increase O&M expenses for a PSMS program in the amount of $500,000. Pet. Ex. 3, Attach. 3-D, Adjust. OM 2M.

Mr. Roberts testified that a critical valve program is designed to be available for use in emergencies to reduce the time needed to shut down a segment of line. NIPSCO is revisiting its current critical valve plan to determine improvements that will provide reduced incident response and system shut-down time, ensure safety of employees and the public, and minimize any environmental impact from methane emissions. He testified the critical valve program will review and update NIPSCO's gas standard, defining valve installation requirements, operating procedures, and implementation protocols. It will define isolation area size and customer count. Once defined, a gap analysis will be conducted to determine the number of critical valves required, whether some current valves may be re-classified, and the number of new critical valves installed. Mr. Roberts provided testimony supporting Adjustment OM 2O to increase O&M expenses for a proposed critical valve program in the amount of $500,000. Pet. Ex. 3, Attach. 3-D, Adjust. OM 2O.

Mr. Roberts supported an adjustment for increased right-of-way encroachment program expenses. He testified NIPSCO monitors its system through a frequency of patrols and leak surveys. The number of High Consequence Areas has grown from 105 miles in 2010 to 120 miles in 2016. He explained that as building and construction continues to occur near NIPSCO's rights-of-way, NIPSCO recognizes the need to be aggressive in its enforcement of any encroachment activity that could either cause damages to the facilities or inhibit the ability to monitor and access the facilities. He testified that NIPSCO recently switched from a five-year leak survey of its distribution system to a three-year survey, improving the ability to identify encroachments more quickly. That change drives additional expenses. Mr. Roberts provided testimony supporting Adjustment OM 2Q to increase O&M expenses $500,000 for a proposed right-of-way encroachment program. Pet. Ex. 3, Attach. 3-D, Adjust. OM 2Q.

Finally, Mr. Roberts testified about PHMSA regulations requiring gas operators to implement written operator qualification programs. He explained that through a written program, each gas operator defines the covered tasks conducted on their system and develops qualification criteria for those covered tasks including the following: (i) evaluations based on knowledge and skill of the individuals performing the tasks; and (ii) associated recordkeeping requirements. He testified that NIPSCO has been implementing an operator qualification program since the inception of the rule and has been utilizing material and protocols established through the Midwest Energy Association's *EnergyU* program. Mr. Roberts testified that a number of high profile incidents that resulted in explosions and loss of life were caused, in part, by a gas company's or contractor's personnel failing to execute specific tasks according to procedures. He also noted that the continually increasing technical demands of successful gas distribution operations require a higher level of knowledge than was historically necessary. NIPSCO is beginning to see a substantial migration of its experienced workforce, and NIPSCO is faced with training a new generation of gas operations employees. Historically, NIPSCO's employees have been experiential learners, perhaps taking 5-10 years of on the job training to truly become proficient. Anticipating that new workers will not have the same opportunity to learn from seasoned workers over a similar time period in the future, Mr. Roberts provided testimony supporting Adjustment OM 2S-18R to increase O&M expenses for a proposed operator qualification program in the amount of $1,000,000. Pet. Ex. 3, Attach. 3-D, Adjust. OM 2S-18R.

G. **Andrew S. Campbell.** Mr. Campbell, Director of Regulatory Support & Planning with NIPSCO, described NIPSCO's gas infrastructure and explained how the quality of that system supports the safe delivery of natural gas. He also described the system rationale for Natural Gas Pipeline Company of America ("NGPL") - NIPSCO's 134th Street Project, as well as the State Line Regulator Station Project, Topeka Betterment Project, and projects that are expected to be in-service by the end of 2018 as part of the Gas TDSIC Plan. In addition, he described and provided support for certain changes to NIPSCO's tariff. Specifically, he discussed the operational rationale and natural gas market drivers behind proposed changes to Rule 13 contained in the General Rules and Regulations, as well as changes to Rate 428, Rate 438, Rider 431, and the introduction of Rider 189, which contains terms that previously were included in Rate 428. Rates 428 and 438 are being designated as Rates 128 and 138, respectively. Additionally, he discussed the planning assumptions that support NIPSCO's forecasted cost of gas sold, forecasted gas in storage, forecasted on-system storage activity, and the pro forma adjustments for LNG liquefaction costs. Finally, he provided support for the adjustment to NIPSCO's Forward Test Year revenues to remove forecasted off-system displacement revenues.

Mr. Campbell testified NIPSCO's gas distribution system is a dispersed/multiple city-gate, integrated transmission/distribution, and multiple pressure-based system, providing gas service to more than 819,000 customers. At the end of 2016, NIPSCO had 17,228 miles of transmission and distribution lines. He stated NIPSCO has invested substantially over the years in its gas distribution system, resulting in a very low percentage of priority pipe (46 miles or 0.27% of total system). In addition to regular maintenance and inspection programs, the recent and planned investments to NIPSCO's gas system approved in Cause No. 44403 as part of its Gas TDSIC Plan are intended to increase long term reliability by replacing infrastructure and allowing access to gas in more rural areas. The projects being undertaken also demonstrate NIPSCO's commitment to providing a safe and reliable supply of gas to its customers. He stated that reducing a gas utility's priority pipe percentage increases safety and reliability of the system. A low priority pipe percentage also reduces repair costs because of the much lower likelihood of developing leaks. Priority pipe is more likely to develop leaks that require repair and lead to higher unaccounted for gas ("UAFG") costs. Gas companies aspire for a low percentage of priority pipe to achieve these benefits. He explained that UAFG is the portion of gas that is delivered to the distribution system which cannot be accounted for through sales or other known uses. UAFG is a cost of providing gas service to customers because all gas systems, regardless of how well maintained, have some level of UAFG. A well maintained system will reduce this expense because less gas is lost through leaks. NIPSCO's low percentage of priority pipe helps NIPSCO maintain a low UAFG.

Mr. Campbell testified NIPSCO uses a third-party gas network hydraulic simulation model for new design applications. The two primary variables considered are the maximum quantity of gas that will be needed to meet demand and the minimum pressure needed at the delivery point. Because the maximum demand on the system generally occurs on the coldest day, NIPSCO has established "Design Day" peak conditions based on extreme weather probability for use in its model. He stated NIPSCO evaluates historical weather to determine the design temperature that is used to project system load in the hydraulic simulation model. NIPSCO applies a 1 in 33 probability factor to determine the Design Day temperature. This 1 in 33 probability indicates that there is a 3% probability that any winter may have at least one day equal to or colder than the Design Day temperature. Based on this analysis, NIPSCO's Design Day represents a daily average of -15° Fahrenheit (or 80 heating degree days). NIPSCO then evaluates the gas usage of all of its stations during the Design Day to determine the amount of gas that will be used and to design the system to ensure that adequate supplies of gas are available. This model also is used to evaluate whether new customers or growing usage will require infrastructure improvements. He explained that the consequences of failing to meet Design Day peak demand are significant because of the basic operation of a gas system. If usage exceeds the design capacity, gas pressure will degrade to a point where gas flow will cease for customers located farther away from the supply source. Appliances using gas will shut-down because there is no flowing gas supply. Appliances that rely on a pilot light may allow small amounts of gas to leak into the premises when service pressure resumes because the gas is not being burned. NIPSCO must send personnel out to these customers' meters to shut-off the gas supply to avoid this danger and then turn the meter back on when gas is available. He stated that NIPSCO's current and proposed tariff allows the ability to issue curtailments of gas flow. He explained that NIPSCO's proposed changes to Rule 13, proposed Rates 128 and 138, as well as Rider 131 (formerly Rates 428, 438, and Rider 431), provide a more concise and transparent approach to the implementation of curtailments and potential penalties associated with non-compliance. He noted that as of the filing date NIPSCO has never had to issue a curtailment on its system.

Mr. Campbell identified the capital projects expected to be completed and in-service before the close of the Forward Test Year. Mr. Campbell testified the 134th Street Project is a proposed interconnection between NIPSCO's system and NGPL in Illinois that is necessary to maintain adequate and reliable gas supply to a portion of NIPSCO's system due to the retirement of a piece of pipe located in Illinois. He explained that the current pipe is owned by a neighboring utility and is being retired due to integrity concerns. NGPL leases this piece of pipe to supply NIPSCO. He testified that the 134th Street Project is expected to be in-service by the end of 2018. He stated that other alternatives were evaluated when considering the 134th Street Project, including other proposals from NGPL and possible build-outs within the NIPSCO system, but that NIPSCO determined that the 134th Street Project represented the most economical solution for NIPSCO's customers. He explained that the 134th Street Project involves the construction of approximately one mile of pipe in Illinois (to be owned by NGPL) versus approximately three miles of pipe that would have been required to complete the build-out of the NIPSCO system. NIPSCO and NGPL are negotiating an interconnect agreement designed to ensure protections for both companies with the anticipated project costs reflected as an operating lease. Mr. Campbell provided testimony that detailed the development and calculation of Adjustment OM 7-18R to annualize the Forward Test Year depreciation expense and interest expense related to the 134th Street Project capital lease and re-classify it to O&M expense in the amount of $2,436,000. Pet. Ex. 3, Attach. 3-B, 3-C, and 3-D, Adjust. OM 7-18R.

Mr. Campbell also testified about the State Line and Topeka capital projects that are expected to be in-service by the end of 2018. He explained that the State Line project is a new regulator station on the west side of NIPSCO's system that will allow pressure control of the 483 pounds per square inch ("PSI") system. It will provide additional protections from over-pressure conditions and increase NIPSCO's flexibility on that portion of the system. He explained that the Topeka project addresses demand growth on a portion of NIPSCO's system. It is necessary to ensure the delivery of gas during peak conditions to customers served by that portion of the system. It involves an upgrade to approximately three miles of pipe near Topeka, Indiana. Mr. Campbell stated these projects are necessary for NIPSCO to continue to provide adequate and reliable service to a portion of its system and are prudent investments to NIPSCO's system. They address demand growth, allow for better control of NIPSCO's system, and demonstrate NIPSCO's continued system investment and commitment to provide safe and reliable supplies of natural gas.

Mr. Campbell testified the Aetna-LaPorte and Stateline-Highland Junction projects are planned investments to NIPSCO's gas system approved in Cause No. 44403 as part of its Gas TDSIC Plan. Both projects are expected to be in-service in 2018 and represent significant upgrades to NIPSCO's system. He explained that the projects replace at-risk pipe to reduce the risk to public safety and help prevent unscheduled outages or repairs. They have also been equipped with in-line inspection capabilities (known as piggable) to enable inspections of the pipe with minimal impact to customers and further reduce risks associated with pipeline integrity. He noted that remotely operated valves have also been installed to improve the ability to quickly isolate portions of the system in the event of a major leak or rupture. The Aetna-LaPorte project also allows that portion of the system to operate at higher pressures to improve system flexibility and pressure support to customers.

Mr. Campbell provided testimony that described NIPSCO's gas delivery system, including its transmission, distribution, and storage systems. He also testified regarding system underground and LNG storage resources. Mr. Campbell supported Adjustment OM 2T with a detailed explanation of the rationale for and derivation of the adjustment that increases operating expenses in the amount of $870,227 for budgeted increases in LNG expense for the 12 months ending December 31, 2018. Pet. Ex. 3, Attach. 3-C and 3-D, Adjust. OM 2T.

Mr. Campbell described "line pack" as the amount of gas stored in the high pressure loop as the pressure ranges between 350 and 540 PSI. He explained that when more gas enters the system from the interstate pipelines than is delivered to the customers, the gas is stored in the pipelines, and the pressure in the pipelines increases. When more gas leaves than enters the system, gas stored in the pipeline is used, and the pressure in the pipeline decreases. He explained that line pack is unique in that since pressure changes in the system are managed by the pressures supplied by the interstate pipelines, line pack is a no cost benefit NIPSCO is able to provide to its customers.

Mr. Campbell also explained how NIPSCO measured forecasted gas in storage for this proceeding. He stated that firm storage service contracts with NGPL, Panhandle Eastern Pipeline Company, ANR Pipeline, Moss Bluff Hub Partners, L.P., Washington 10 Storage Corporation, and Egan Hub Partners, L.P. provide an annual peak working storage capability of approximately 32,300,000 Dth, with maximum daily withdrawal capability of approximately 607,000 Dth to meet winter peaks, after allocations to the Choice Suppliers. He explained that NIPSCO develops a storage plan that includes both planned injection and withdrawal activity required to meet customers' needs based upon projected annual billing determinants provided by NIPSCO Witness Efland. He noted that NIPSCO's overall philosophy for injections and withdrawals is a ratable, but weighted approach. NIPSCO seeks to maintain maximum flexibility for monthly and daily system balancing. He explained that all forecasted gas in storage levels are determined using forecasted demand and are targeted to achieve approximately 92% of contracted off-system storage and on-system storage volumes at the start of the winter season. The dollar value associated with the forecasted gas in storage is determined through this plan. It is priced using the forward price New York Mercantile Exchange curve based on the projected purchases made and injected into storage in a given month to determine a total cost of gas. The total cost of gas is then utilized to determine a WACOG. He explained that as shown in Petitioner's Exhibit No. 3, Attachment 3-E, RB-5, a 13-month average for the Forward Test Period is calculated using the resulting monthly projected gas in storage inventory volumes and costs.

Mr. Campbell explained the derivation of NIPSCO's forecasted cost of gas sold. He stated that the bulk of NIPSCO's demand is supported through its storage activity. NIPSCO utilizes the total gas cost and WACOG determined in its forecasted gas in storage for its cost of gas sold to align with the forecasted plan utilized in this proceeding. He testified that the gas cost itself is forecasted and reconciled on a quarterly basis through NIPSCO's GCA tracker proceedings. He noted that the forecasted total gas cost provided to the Financial Planning department that allocates gas costs to each rate tariff based on projected annual billing determinants, was provided by NIPSCO Witness Efland.

Mr. Campbell described Rule 13 of NIPSCO's Rules and Regulations. He stated that Rule 13 gives NIPSCO the ability to curtail service when sufficient volumes of gas, in the judgment of NIPSCO, are not available to NIPSCO to meet all existing and reasonably anticipated demands for service or in order to protect the integrity of the gas system. He explained that Rule 13 as proposed also will ensure the operational flexibility necessary to curtail use on all, or just a portion of, NIPSCO's system. He explained that the two main circumstances when NIPSCO might declare a curtailment include: (i) under an emergency circumstance when curtailment is required to forestall imminent and irreparable injury to life or property; and (ii) non-emergency conditions when curtailment is necessary to ensure that NIPSCO is able meet customer demands or protect the integrity of the system. He explained that NIPSCO is not proposing to change the procedures for emergency curtailments. NIPSCO will continue to reserve the right to order a curtailment without regard to the priority of service or without first declaring a Critical Period. In general, he explained that NIPSCO's proposed changes are designed to clarify and simplify the procedures for declaring a non-emergency curtailment and to provide a more equitable approach among customers subject to possible curtailments.

Mr. Campbell provided testimony that explained the priority of service curtailments as well as the calculation of curtailment thresholds. He explained that interruptible services under Rates 130, 134A, and 140 and Riders 142A, 147, and 148 will be interrupted prior to curtailment of any firm services. Upon declaration of a curtailment, firm services shall be prioritized and curtailed in the following order: (i) transportation service under Rates 128 and 138 above the annual Curtailment Threshold calculated as the 50th Percentile of Daily Usage; (ii) transportation service under Rates 128 and 138 between the annual Curtailment Threshold calculated as the 20th Percentile of Daily Usage; and (iii) service under all other firm Rates.

He explained that to determine the Curtailment Thresholds of 50th and 20th Percentiles of Daily Usage, NIPSCO reviewed customer usages and determined the 50th Percentile of Daily Usage and the 20th Percentile of Daily Usage represented meaningful curtailment levels. The "50th percentile" is the median gas usage by customers and represents a level of usage that NIPSCO typically observes during normal operations. In instances where a curtailment at the 50th percentile Curtailment Threshold would be enacted, many customers will be operating at or near this level. Accordingly, any action required by customers to curtail usage to this level should be limited. This curtailment step in Rule 13 is generally designed to limit upward movement by current Rate 428 and 438 customers from the median level. He stated that NIPSCO's current Rate 428 and 438 customers are generally referred to as "process load" customers, and that process load usage typically does not vary with weather conditions and remains relatively flat over time, resulting in NIPSCO proposing the second Curtailment Threshold be the 20th Percentile of Daily Use. He explained that the "20th Percentile" represents a meaningful step just before enacting Emergency Curtailments. Because of the flat nature of the process load, that may represent less than approximately 100,000 Dth of relief across all Rate 428 and 438 customers from what is characterized as normal operations, which is the 50th Percentile level of usage.

Mr. Campbell testified that he was not aware of any curtailment events on NIPSCO's system. NIPSCO's gas system has proven to be robust and reliable. He stated that although NIPSCO has not experienced a curtailment event, NIPSCO is proposing changes to the curtailment process to make implementation more transparent. A more concise and transparent process is easier to implement, benefiting all customers by increasing the likelihood of safe and reliable supplies of natural gas during maximum send out conditions. He indicated the proposed changes allow all customer classes to be interrupted, aside from the interruptible classes, to maintain some level of service during a curtailment period.

Mr. Campbell described the changes to NIPSCO's transportation rates. He explained that NIPSCO hopes to achieve three primary objectives in changing Rates 428 and 438 as follows: (i) simplify several sections that have duplicative language; (ii) clarify the circumstances under which NIPSCO can implement curtailment; and (iii) refresh certain language based on recent operational experience. He stated that proposed Rates 128 and 138 would continue to be available to the same groups of customers to which Rates 428 and 438 were available, respectively. He testified that most of the proposed changes to the Character of Service provisions are designed to consolidate similar language, make the tariff easier to read and understand for customers, and include requirements common to all zones in a single written description. Mr. Campbell explained that Proposed Rates 128 and 138 include a table showing the upstream pipelines and nominating meter points that are available to each individual zone. The table can be used as a readily available resource for customers and their third-party suppliers to identify available nominating meters by zone. He testified that NIPSCO is proposing to change the language in Rates 128 and 138 to reserve the right to further restrict the availability of approved delivery points to certain customers based on system conditions and to make clear that Rider 131 may apply in situations where customers do not adhere to nomination and/or meter cap restrictions. He stated the proposed change is intended to allow NIPSCO to restrict deliveries without calling a critical period. In those instances, it is crucial that NIPSCO have the flexibility to restrict the availability of certain delivery points. However, by not calling a critical period, customers do not have to pay a penalty during those times for over-deliveries. Mr. Campbell noted that in the event of a *force majeure* or a need for system maintenance, NIPSCO endeavors to let customers know as far in advance as possible. He stated Rule 13 of NIPSCO's terms and conditions for service addresses "Service Interruptions and Curtailments." Accordingly, the capacity curtailment language has been eliminated from proposed Rates 128 and 138, and a reference to Rule 13 of NIPSCO's terms and conditions for service has been added to eliminate duplicative tariff language that could cause confusion.

Mr. Campbell testified clarifying changes were made to the Imbalances sections of NIPSCO's transportation tariffs to shorten them and make them more user friendly for customers. Instead of including repetitive terms describing the balancing services available to each of three categories of customers, the revised tariffs define each category of customers and include a new table indicating what services are available in each customer category. He stated NIPSCO is proposing to allow customers to make more frequent bank capacity changes. To facilitate this additional flexibility, the maximum balancing account capacity limit available to each Customer or Pool Operator's customers in aggregate under Rates 128 and 138 shall be 50% of the customer's average daily use recorded during the previous calendar year. NIPSCO is also proposing that the maximum amount of bank capacity that NIPSCO will sell annually will be 60% of the total annual average daily use of all customers on Rates 128 and 138, and the firm daily injection/withdrawal limit will be 2% of the customer's capacity limit as opposed to "the capacity limit divided by fifty-seven (57)." This simplifies the language and increases flexibility as the current language equates to approximately 1.75%. He testified that the current amount of bank capacity is unlikely to put a significant amount of strain on its system, but that the limits being proposed are more in line with the storage capacity that customers will actually use and to allow customer bank capacity growth while minimizing system strain.

Mr. Campbell described the proposed changes to the cash out provisions of Rates 428 and 438. He explained that NIPSCO is proposing to change the cash out provision in Rates 128 and 138 to a daily No-Notice Gas Undertake Service price for that day and proposing a tiered approach to No-Notice Gas Undertake Service. He stated that NIPSCO believes these changes simplify the language and allow for an equilateral approach between No-Notice Gas Undertake Service and No-Notice Gas Overtake Service. This change reflects the fact that the services are direct opposites and depend on whether the customer is in an undertake or overtake position. He testified that both No-Notice Gas Undertake Service and No-Notice Gas Overtake could be subject to penalties, but that will now be treated as a firm service.

Mr. Campbell testified NIPSCO is proposing a number of minor updating or clarifying changes to make them easier to understand. NIPSCO also is proposing to move certain information that currently is imbedded in tariff language to separate sections so that it will be easier for customers to find. The rate section now includes pool fees and charges currently delineated separately in contracts. The Pipeline Penalty Allocation section clearly defines the pipeline penalty allocation methodology.

Mr. Campbell also stated NIPSCO is proposing a balancing charge for daily imbalances between 5% and 10% and proposing to update its bank capacity charge. The daily imbalance charge for imbalances between 5% and 10% was determined utilizing the weighted average variable costs associated with NIPSCO's current off-system storage portfolio on a maximum storage quantity basis. This approach is intended to accomplish two objectives as follows: (i) capture cost incurred as a result of imbalances by applying the appropriate price signals to Rates 128 and 138 customers; and (ii) fairly compensate NIPSCO's GCA customers for the balancing activity of the transport customers. The rate calculated is divided by two to account for some natural netting between customers. NIPSCO utilized a volume weighted average of its current off-system storage portfolio that captures the cost difference between baseload storage and no-notice / high-turn storage services. This approach is essentially the opportunity cost incurred by NIPSCO's GCA customers by maintaining more flexible storage assets for system balancing.

Mr. Campbell provided an overview of new Rider 189. He stated Rider 189 is an optional service available to Rate 128 Category A customers whose gas requirements during the most recent calendar year average at least 3,000 Dth per day and have the propensity for large changes in intraday usage as part of normal business operations. This service is commonly referred to as "burner tip balancing." In some instances, NIPSCO may require Rate 128 customers to take balancing services under Rider 189 in the event NIPSCO is unable to balance the customer's load under traditional methods. He stated NIPSCO is reintroducing the pipeline burner tip balancing as an additional option for customers to cover imbalances and to offer an attractive solution for new customers with unique operational characteristics such as a large natural gas power generator. He stated that with the reintroduction of pipeline burner tip balancing, NIPSCO is proposing increased flexibility with the ability to have multiple Swing and Non-Swing Pipelines which allows new customers with large variable loads to connect to NIPSCO's system while not burdening NIPSCO's existing customers with the possibility of increased system balancing charges.

Mr. Campbell provided an overview of the changes to Rider 431. He stated that currently Rider 431 is called the "Commercial and Industrial Temporary Emergency Service Rider." The Rider presently addresses "Critical Overtake Days" which in essence are days when NIPSCO's system is operating at near design capacity, jeopardizing the operational integrity of all or a portion of the system, or the system is experiencing certain other capacity-related issues. NIPSCO is proposing to change Rider 431, by introducing the concept of a Critical Undertake Day. Accordingly, NIPSCO is proposing to change the name of Rider 431 to "Critical Undertake Day or Critical Overtake Day Penalty." He stated that the term "Critical Undertake Day" is defined in Rider 431. In essence, a Critical Undertake Day is a day on which one of the following occurs: (i) any area(s) of NIPSCO's system is operating or expected to be operating at or near minimum demands; (ii) NIPSCO's storage and balancing resources are being used at or near their maximum injection capability; or (iii) NIPSCO's pipeline transporters, suppliers, or other utilities issue or declare an Operational Flow Order or the equivalent of a Critical Undertake Day. Mr. Campbell stated that imbalances that occur on Critical Undertake Days are just as detrimental to the operation of NIPSCO's gas system as imbalances on Critical Overtake Days. When NIPSCO has too much gas being left on its system, it can present operational issues that can result in an increased risk of pipeline penalties.

Mr. Campbell described how NIPSCO is proposing to address Critical Overtake Days and Critical Undertake Days. He stated that imbalances of 2% or greater on Critical Overtake Days and Critical Undertake Days will be assessed a per therm penalty charge. Imbalances exceeding 20% will be assessed a higher penalty. He explained that NIPSCO will not declare Critical Undertake Day(s) and Critical Overtake Day(s) concurrently. He stated that currently, the imbalance penalty is three times the applicable city-gate midpoint price, or $6.00 per Therm. NIPSCO believes the current penalty is sufficient to encourage customers to manage their imbalances. However, NIPSCO believes a tiered approach will help provide an incentive for customers to minimize imbalances. He noted that the tiers for both Critical Undertake Days and Critical Overtake Days are aligned.

Mr. Campbell supported Adjustment REV 5-18R and the resulting impact on the Forward Test Year. Pet. Ex. 3, Attach. 3-B and 3-D. That adjustment decreases Forward Test Year operating revenues by $293,000 to remove forecasted off-system displacement revenues. Mr. Campbell also described off-system displacement revenues. He stated that off-system displacement revenues are generally the result of off-system transactions that involve a locational exchange of gas whereby NIPSCO delivers gas to one side of the NIPSCO system, and the counterparty delivers an equal volume to another side of the NIPSCO system. These transactions involve the exchange of a commodity at a point in time with no additional costs incurred by NIPSCO's customers. Due to the fact that there are no additional costs incurred to NIPSCO customers and the gas is replaced equally, in volume and price between the points, the fee paid by the counterparty is kept by NIPSCO and is booked as off-system displacement revenue. He stated that NIPSCO's shareholders assume all risks associated with off-system displacement transactions so the transactions involve assets that are not included in rate base. These transactions traditionally have been excluded from NIPSCO's GCA revenues.

H. Ronald J. Harper. Mr. Harper, Director of Corporate Budgets with NCSC, provided background on the relationship between NCSC and NIPSCO and supported the O&M expenses associated with the Corporate and Operating services provided by NCSC to NIPSCO. He also sponsored any adjustments to those expenses for the Historic Base Period, 2017 Budget Period, or the Forward Test Year.

Mr. Harper explained the structure and role of NCSC. He testified NCSC was established to provide centralized services to its affiliates. Providing services on a centralized basis enables the affiliates to realize benefits, including use of personnel and equipment, and the availability of personnel with specialized areas of expertise. He stated there are two types of billings made to affiliates, including NIPSCO, as follow: (i) contract billing; and (ii) convenience billing. Contract billings represent NCSC labor and costs billed to the respective affiliates. Contract billings are identified by billing pools. He explained that contract billed charges may be direct-billed (billed directly to a single affiliate or function, including NIPSCO Electric, NIPSCO, or NIPSCO Common), or allocated (split between several affiliates), depending upon the nature of the expense. He also explained that convenience billing reflects payments that are routinely made on behalf of affiliates on an ongoing basis, including employee benefits, corporate insurance, leasing, and external audit fees. Each affiliate is billed its proportional share of the payments made in the respective month. NCSC makes the payment to the vendor, and the charges for the services are recorded directly on the books of the affiliate.

Mr. Harper testified NCSC has executed an individual Service Agreement with each affiliate that is updated from time to time so that all affiliates that receive service from NCSC are subject to the same Service Agreement. It designates the types of services to be performed and the method of calculating charges. He stated NCSC is not responsible for assessing the split between costs appropriately attributable to NIPSCO's Electric and Gas operations unless the costs are directly billed to NIPSCO Electric or NIPSCO, which NCSC began doing effective January 1, 2009.

Mr. Harper testified NCSC was regulated by the SEC under the Public Utility Holding Company Act of 1935 until February 8, 2006, when the Public Utility Holding Company Act of 2005 ("PUHCA 2005") was enacted. PUHCA 2005 transferred regulatory jurisdiction over public utility holding companies from the SEC to FERC. Pursuant to FERC Order No. 684 issued October 19, 2006, centralized service companies (like NCSC) must use a cost accumulation system, provided such system supports the allocation of expenses to the services performed and readily identifies the source of the expense and the basis for the allocation. In compliance with PUHCA 2005 and FERC, NCSC uses a billing pool system to collect costs that are applicable and billable to affiliates, including NIPSCO. Costs are directly charged to a particular affiliate whenever possible, and in cases involving more than one affiliate, the billing pool system defines how expenses are allocated among the participating affiliates. Mr. Harper testified NCSC allocates costs for a particular billing pool in accordance with the bases of allocation that have been previously approved by the SEC and filed annually with FERC. Descriptions of each basis of allocation is provided in each Service Agreement. He explained that NCSC currently updates the statistical data used in the approved allocation bases at least on a semi-annual basis. NCSC provides NIPSCO's leadership team the opportunity to review, discuss, and provide feedback prior to publishing the new allocation percentages.

Mr. Harper testified that system controls are in place to restrict the use of billing pools to companies benefitting from the services being provided. He noted that NIPSCO's Internal Audit group conducts an annual review of cost allocation procedures and makes recommendations related to contract and convenience billing processing. Mr. Harper noted that NiSource, including NCSC, underwent a FERC audit, Docket No. FA11-5-000 covering the period January 1, 2009 through December 31, 2010. No adverse comments were issued regarding NCSC's allocation methods.

Mr. Harper testified all services are provided at cost, including compensation for use of capital. He stated affiliates have the right to meet with NCSC to review and assess the quality, costs, and/or allocations of the services being provided. NIPSCO's accounting team performs a review of the bill, makes selections to review charge details for reasonableness and accuracy, and alerts NCSC accounting if they disagree with a charge.

Mr. Harper testified the NCSC budget development process is consistent with the NIPSCO planning process from a timing and planning standpoint. He explained that the budget process used to develop the Forward Test Year was the annual financial plan for 2017, consisting of a six year horizon. The first two years were broken down by month, and the balance was completed on an annual basis. He stated targets for the NCSC functions are grounded in a trailing 12-month historical spend with a 2% inflation for each year thereafter, adjusted to account for one-time items and where future planned work varies from history. NCSC's functional leaders then develop their budgets based on their commitments, which include day to day operations and requests from their business partners.

Mr. Harper also provided details about the processes that drive the derivation and approval of NCSC budgets. He testified about the substance and calculation of Adjustment OM 19-16 to reduce Corporate Service Fees expenses in the amount of $95,141. Pet. Ex. 3, Attach. 3-D, Adjust. OM 19-16. He also testified regarding Adjustment OM 20-16 to reduce Operations-Corporate Service Fees expenses in the amount of $33,829. Pet. Ex. 3, Attach. 3-D, Adjust. OM 20-16.

Mr. Harper explained the calculation of the Forward Test Year level of O&M expense. He opined that the amount is reasonable and representative of NIPSCO's ongoing cost of providing service. He explained that the Forward Test Year level of O&M expense is justified by the projected needs of NIPSCO to serve its customers.

I. Christopher D. Smith. Mr. Smith, Vice President of Human Resources with NCSC, described and supported the reasonableness and competitiveness of NIPSCO's wages and salaries, incentive compensation, and employee benefits. He supported NIPSCO's pro forma adjustment to Forward Test Year operating expenses related to incentive compensation.

Mr. Smith testified that NiSource's compensation philosophy is to compensate employees competitively in comparison to the utility industry and general industry on a total rewards basis. Mr. Smith testified NiSource follows this philosophy to attract, retain, and motivate employees who are qualified to perform the needed functions of the particular position. According to Mr. Smith, this compensation philosophy enables NIPSCO to meet its obligation to provide safe, reliable, and cost-effective gas service to its customers. He explained that NIPSCO's total rewards program includes the following: (i) market-driven base compensation (rewarding employees in a manner that is competitive with the external job market); (ii) market-driven performance adjustments/merits; (iii) long- and short-term incentives and profit sharing; and (iv) health and welfare benefits that differ for various levels in the organization.

Mr. Smith explained that NCSC in conjunction with Mercer LLC, an outside benefits consultant, compared total cash compensation provided by NCSC and NIPSCO to other utilities and to general industry companies. Mr. Smith testified that the analyses demonstrate that NIPSCO's base salary and total cash compensation are reasonable when compared with other utilities and general industry employers. Mr. Smith provided analyses based on position, function, and level on a comparison basis for the utility and general industry nationally. Attachment 9-B compares base and total cash compensation for NCSC positions with at least five or more incumbents in both utility and general industry from a variety of functions and levels relative to the industry nationally. Mr. Smith testified as Attachment 9-B shows, the NCSC base salary and total cash compensation are reasonable and competitive. Specifically, NCSC is 6.1% below the market comparison data in base pay and 2.9% below the market comparison data in total cash compensation for these positions compared nationally.

Mr. Smith testified that NiSource's and NIPSCO's incentive compensation is based first upon meeting certain corporate incentive plan goals, and if those goals are met, an incentive pool is created for distribution to NIPSCO employees. He explained that incentive payouts for bargaining unit and non-exempt employees are determined arithmetically. Incentive payouts for all other employees are determined in large part by an assessment of performance against individual performance objectives, focusing on customer-oriented goals such as safety, customer service, quality of service, and containment of costs. Mr. Smith provided testimony that explained the basis for and calculation of Adjustment OM 16-16 to decrease Historic Base Period operating expenses in the amount of $1,031,455. Pet. Ex. 3, Attach. 3-B, 3-C, and 3-D, Adjust. OM 16-16.

J. **John J. Spanos.** Mr. Spanos, Senior Vice President with Gannett Fleming Valuation and Rates Consultants, LLC, testified about the depreciation analysis he performed related to NIPSCO's gas plant as of December 31, 2016, and his recommendation of depreciation rates for forecasted gas plant as of December 31, 2018. He explained the methods and procedures used in the Depreciation Study and sponsored Attachment 10-B setting forth the results of that study, and Attachment 10-C setting forth the results of his depreciation analysis related to NIPSCO's projected gas plant in-service as of December 31, 2018.

Mr. Spanos testified about the principal conclusions of his study and the bases for them. He explained that the proposed depreciation accrual rates by account were based on his review of historical data, NIPSCO's operating maintenance practices, and the application of informed engineering judgment. He testified that in preparing the Depreciation Study, he followed generally accepted practices in the field of depreciation and valuation. He explained that while the interim survivor curves and the life spans for underground storage and LNG facilities are longer than the lives currently being used, the overall impact of annual depreciation expense as of the projected plant in-service date of December 31, 2018, is an increase. The increase is driven largely by two factors as follows: (i) the elimination of the depreciation credit mechanism approved in NIPSCO's last rate case; and (ii) NIPSCO's substantial investment in gas utility plant since that time.

Mr. Spanos testified that he used the straight-line remaining-life method of depreciation, with the equal-life group procedure. He explained that this method of depreciation aims to distribute the unrecovered cost of fixed capital assets over the estimated remaining useful life of each unit or group of assets in a systematic and rational method. His recommended annual depreciation accrual rates as of December 31, 2016, for NIPSCO's gas plant are set forth in the Depreciation Study on Attachment 10-B, and the projected annual depreciation accrual rates as of December 31, 2018, are set forth on Attachment 10-C applicable for the forecasted Forward Test Year assets.

Mr. Spanos testified that he determined the recommended annual depreciation accrual rates in two phases. In the first phase, he estimated the service life and net salvage characteristics for each depreciable group, meaning each plant account or subaccount identified as having similar characteristics. In the second phase, he calculated the composite remaining lives and annual depreciation accrual rates based on the service life and net salvage estimates determined in the first phase.

Mr. Spanos testified that for the first phase, the service life and net salvage studies consisted of the following: (i) compiling historic data from records related to NIPSCO's plant; (ii) analyzing this data to obtain historic trends of survivor and net salvage characteristics; (iii) obtaining supplementary information from management and operating personnel concerning practices and plans as they relate to plant operations; and (iv) interpreting the data and the estimates used by other gas utilities to determine average service life and net salvage characteristics. He explained that he used the retirement rate method for all gas accounts to analyze the service life data for NIPSCO. He noted that retirement rate method is the most appropriate method when aged retirement data are available because this method determines the average rates of retirement actually experienced by NIPSCO during the period covered by the study. Mr. Spanos explained that in the life span technique used in his study, survivor characteristics are described by the use of interim survivor curves and estimated probable retirement dates. He noted that the life span technique has been presented to and accepted by many public utility commissions across the United States and Canada, including the Commission. Mr. Spanos testified that the bases for the probable retirement years are life spans for each facility that are based on judgment and incorporate consideration of the age, use, size, nature of construction, management outlook, and typical life spans experienced and used by other gas utilities for similar facilities. He further testified that he made field reviews of a representative portion of NIPSCO's property in April 2017. He conducted field reviews in January and July of 2010. Mr. Spanos also explained that he estimated the net salvage percentages based on judgment. He incorporated analyses of the historical data for the period 1999 through 2016 for gas plant. He considered estimates for other gas companies for most accounts.

Mr. Spanos testified that during the second phase of the Depreciation Study, he calculated the composite remaining lives and annual depreciation accrual rates. After estimating the service life and net salvage characteristics for each depreciable property group, he calculated the annual depreciation accrual rates for each group based on the straight-line remaining-life method using remaining lives weighted consistent with the equal-life group procedure. The annual depreciation accrual rates were developed at December 31, 2016. He explained that the straight-line remaining-life method of depreciation allocates the original cost of the property, less accumulated depreciation, less future net salvage, in equal amounts to each year of remaining service life. He further explained that the equal-life group procedure is a method for determining the remaining life annual accrual for each vintage property group. Under this procedure, the future book accruals (original cost less book reserve) for each vintage are divided by the composite remaining life for the surviving original cost of that vintage. The vintage composite remaining life is derived by summing the original cost less the calculated reserve for each equal-life group and dividing by the sum of the whole life annual accruals. Mr. Spanos testified that amortization accounting was applied to accounts with a large number of units with small asset values. He noted that amortization accounting was approved by the Commission in the November 4, 2010 Order in Cause No. 43894 as being only appropriate for certain general plant accounts, representing slightly more than 1% of depreciable plant.

Mr. Spanos explained his calculation of the forecasted depreciation rates as of December 31, 2018. First, the plant in-service and book reserve were brought forward from December 31, 2016 to December 31, 2018 based on the capital budget by account and by year. The book reserve by account as of December 31, 2018, was developed by adding the annual accruals and gross salvage each month and subtracting retirements and cost of removal each month for the two-year period. Once the plant in-service as of December 31, 2018, was developed by vintage within account and the book reserve is developed by account, then the December 31, 2018 depreciation rates were calculated using the same methods and procedures as in the 2016 Depreciation Study.

K. <u>Ann E. Bulkley</u>. Ms. Bulkley, Senior Vice President of Concentric, testified that Concentric was engaged by NIPSCO to perform a study of the value of its natural gas distribution system assets as well as the allocation of common plant assets that are attributable to the natural gas distribution system (collectively referred to as the "natural gas utility assets"). Her analysis developed the current value of NIPSCO's natural gas utility assets in-service as of December 31, 2016, using a cost-based valuation methodology, the Reproduction Cost New Less Depreciation ("RCNLD") or "Current Cost" approach. She also developed and sponsored the projected value of NIPSCO's natural gas utility assets as of December 31, 2018, based on NIPSCO's projections for capital investments made through those dates.

Ms. Bulkley testified the appraisal procedure consisted of five steps as follows: (i) the development of current costs of the properties by trending the original costs; (ii) a determination of physical and functional depreciation involving field inspection, analysis of NIPSCO's records and statistics, and various other calculations; (iii) the application of depreciation factors to the current costs to result in the current value; (iv) a review of NIPSCO's projections for the year ending December 31, 2018; and (v) the final assembly of the appraisal and supporting data, including preparation for this proceeding.

Ms. Bulkley testified that she reviewed the following information: NIPSCO's continuing property records; FERC Form No. 2; capital budgets; programmed maintenance schedules; proposed useful lives; and portions of NIPSCO's annual filings to the DOT. Additionally, she testified that she inspected NIPSCO's facilities to determine their overall operating characteristics and condition. Her analysis included NIPSCO's transmission and distribution system assets and NIPSCO's general plant accounts, including only the accounts not included in other plant accounts, as defined by FERC's Uniform System of Accounts.

Ms. Bulkley's analysis concluded that the current value of NIPSCO's natural gas utility assets in-service as of December 31, 2016, and December 31, 2018, are $3,117,973,477 and $3,451,911,387, respectively. She testified that the Reproduction Cost New ("RCN") of NIPSCO's natural gas utility plant assets as of December 31, 2016, which is the cost to reproduce the system assets in current dollars, is approximately $6,789.9 million. The RCN of the Common Plant as of the same date is $786.8 million. The portion of the RCN of Common Plant that is allocated to the natural gas utility operations is $213.0 million. Therefore, the RCN of the total natural gas utility assets, including the common plant allocation, is approximately $7,092.9 million, prior to the consideration of depreciation.

Ms. Bulkley testified that, in order to develop her estimate of depreciation, she considered the physical condition of the assets. The physical condition was determined based on the condition of the assets; a review of NIPSCO's records and statistics; and the expected average service life of the assets determined by Mr. Spanos.

Ms. Bulkley explained that she conducted a physical inspection of assets currently in-service and construction work in progress projected to be in-service as of December 31, 2018. She concluded the following: (i) the physical plant and properties are well designed; (ii) they consist of equipment that is consistent with the vintage of the assets installed and the quality of the material; (iii) the properties are being maintained and operated on a coordinated and efficient basis; and (iv) for the foreseeable future, the properties can continue to operate effectively for the purposes for which they have been designed and constructed.

Ms. Bulkley testified that in her analysis she considered physical, functional, and technological depreciation. Physical depreciation was determined based on inspection of the physical condition of the assets. Functional depreciation was determined based on a review of NIPSCO's records and statistics and the expected depreciation of the assets as determined in the Depreciation Study. Ms. Bulkley testified the total physical and functional depreciation for each asset category is the difference between the RCN of that asset category and the RCNLD of that asset category. The total physical and functional depreciation for NIPSCO's gas utility system assets is approximately $2,995.4 million or 42%.

Ms. Bulkley also adjusted her valuation of transmission, distribution, storage, general and common plant to reflect potential changes in technology and productivity. She stated the "technological adjustment factor" is the average change in the output and productivity indexes published by the Bureau of Labor Statistics for the period from 1987 through 2016, which is the period for which there is data available. The resulting factor is approximately 1.00%. The adjustment factor reduces the RCNLD by 1.00% per year based on the average age of the assets in a given asset class. Based on her analysis, the RCNLD of NIPSCO's natural gas utility assets adjusted for technological change as of December 31, 2016, is $3,118 million.

Ms. Bulkley provided testimony that explained how the value of NIPSCO's natural gas utility assets as of December 31, 2018, were estimated and how retirements had been derived. She also explained the process used to trend costs of the 2017 and 2018 projected investments, noting that the allocation of Common Plant as of December 31, 2018, was based on the same methodology that was used for the December 31, 2016 study. She trended the costs using the same approach discussed previously for the natural gas distribution assets and then allocated those costs based on the FERC Form One allocation percentages used in the 2016 study. She also adjusted her pro forma analysis for technological change. Based on her analysis, Ms. Bulkley concluded that the RCNLD of NIPSCO's natural gas utility assets adjusted for technological change as of December 31, 2018, is $3,452 million.

L. <u>Michael D. McCuen</u>. Mr. McCuen, Director of Income Taxes with NCSC, testified about and supported NIPSCO's federal and state income tax expense adjustments and the adjustments for taxes other than income taxes between the Historic Base Period and pro-forma results based on current rates included in the cost of service shown in Ms. Konold's accounting exhibits. He also presented and supported NIPSCO's ADIT and Post 1970 Investment Tax Credit ("ITC") balances and related pro forma adjustments included as components of NIPSCO's Capital Structure. He explained that the income tax calculations were made under the provisions of the Internal Revenue Code of 1986, as amended, and the Indiana Administrative Code. Mr. McCuen testified that he quantified the federal income tax expense beginning with the application of the 35% federal income tax rate applied to pro forma NOI before income taxes less interest expense. He then adjusted this amount to account for the following: (i) differences between the use of accelerated appreciation for income tax return purposes and straight-line depreciation in determining tax expense for book purposes, various tax rate changes, and AFUDC; (ii) certain limitations on the amount of the federal income tax deduction that may be taken on certain categories of expense; (iii) reduction in tax expense for amortization of ITC; and (iv) reduction in tax expense for allocation of parent company's interest expense.

For state income tax expense, Mr. McCuen testified that the tax calculations include Indiana Adjusted Gross Income taxes calculated at 5.875%, adjusted for the following three reconciling items: (i) the non-deductibility of URT; (ii) the excess deferred taxes resulting from the decrease in the state tax rate from 8.5% to 5.875%; and (iii) the non-deductibility of certain expenses.

Mr. McCuen explained NIPSCO's proposal to reflect $12,550,000 in real and personal property taxes and explained the calculation of and basis for Adjustment OTX-1 that resulted in a pro forma adjusted property tax expense of $12,550,000 for the Forward Test Year. He stated these pro forma property tax adjustments are required to account for planned property additions between the Historic Base Period and Forward Test Year.

Mr. McCuen explained NIPSCO's proposal to reflect $8,690,383 in URT and explained Adjustment OTX-5 that resulted in pro forma adjusted URT of $8,690,383 for the Forward Test Year. Mr. McCuen also explained NIPSCO's proposal to reflect $28,384,143 in federal and state income taxes and explained Adjustment ITX 1-18R. He explained the federal and state income taxes for the Historic Base Period per books was $21,354,892. An adjustment to the Historic Base Period was calculated by comparing the actual test period tax expense to the pro forma tax expense, resulting in a $28,384,143 decrease to federal and state income taxes as noted on pro forma adjustment ITX 1-18, bringing the pro forma federal and state income taxes at current rates to a credit of $7,029,251.

Finally, Mr. McCuen also explained adjustments to NIPSCO's capital structure. Adjustments CS 4-17 in the amount of $131,459,150 and CS 4-18 in the amount of $160,913,913 increase Deferred Income Taxes for the period ending December 31, 2017, and December 31, 2018. He stated that deferred income tax balances are forecasted by using a combination of pre-tax income and changes in balance sheet accounts. NIPSCO utilizes Accounting Standards Codification 740 and 980 to account for income taxes in order to reflect its after-tax financial position in its balance sheet. He explained that Adjustments CS 7-17 in the amount of $382,397 and CS 7-18 in the amount of $382,000 decrease Post 1970-ITC for the period ending December 31, 2017 and December 31, 2018. He stated NIPSCO is amortizing ITC over the service life of the property that generated the credits. He testified the tax expense adjustments reflected in Ms. Konold's accounting exhibits were correct and consistent with his description of the applicable tax provisions.

M. <u>Vincent V. Rea</u>. Mr. Rea, Director of Regulatory Finance and Economics with NiSource, testified about the appropriate rate of return on common equity and overall rate of return that the Commission should establish for NIPSCO's gas distribution operations in relation to its revenue requirement calculation. He also addressed the appropriate ratemaking capital structure, WACC, and embedded cost of debt. Finally, he addressed the appropriate fair rate of return to apply to NIPSCO's fair value rate base for its gas distribution operations. Based on his evaluation, he concluded that the cost of common equity for NIPSCO's jurisdictional gas distribution operations is in the range of 10.45% to 10.95%, and that a point estimate at the midpoint of this range, or 10.70%, is the appropriate cost of equity to apply in this case. He determined that NIPSCO's WACC is 6.74%, which is based on NIPSCO's Forward Test Year regulatory capital structure as of December 31, 2018. Mr. Rea opined that this resulting overall cost of capital, if adopted by the Commission, will allow NIPSCO to earn the prevailing opportunity cost of capital, maintain its financial integrity, and attract capital at reasonable terms. The capital structure and WACC presented by Mr. Rea are as follows:

Projected Capital Structure as of December 31, 2018

	Balance (000)	% of Total	Cost	WACC
Common Equity	$2,724,766,793	46.02%	10.70%	4.92%
Long-Term Debt	$1,983,152,080	33.50%	5.25%	1.76%
Customer Deposits	$72,006,141	1.22%	4.76%	0.06%
Deferred Income Taxes	$1,316,021,409	22.23%	0.00%	0.00%
Post-Retirement Liability	$83,343,823	1.41%	0.00%	0.00%
Prepaid Pension Asset	($261,245,296)	-4.41%	0.00%	0.00%
Post-1970 ITC	$2,538,661	0.03%	8.40%	0.00%
Totals	$5,920,583,611	100.0%		6.74%

Mr. Rea explained the general approach taken in determining the cost of common equity, and he supported it with a detailed explanation of the analytical models used and their specific application for this case. He stated he analyzed market-derived data and other financial information for 32 companies comprising two separate proxy groups. He explained that during the course of his evaluation, he applied four well-recognized analytical models to the market and financial data of the selected proxy group companies: the Discounted Cash Flow ("DCF") model, the Capital Asset Pricing Model ("CAPM"), the Risk Premium Method, and the Comparable Earnings Approach. He also evaluated two other model variants of the CAPM, the CAPM with size adjustment and the Empirical CAPM, both of which have been validated by empirical research. Mr. Rea developed his cost of equity recommendations after carefully evaluating the individual cost of equity estimates that were derived from applying the various analytical models to the market and financial data of the proxy group companies. Using a variety of analytical models in conjunction with multiple comparable risk proxy groups ensures that a diversity of investor perspectives are incorporated into the cost of capital evaluation, and provides a solid foundation upon which the analyst can apply informed judgment in making a cost of equity recommendation.

Mr. Rea testified NIPSCO is proposing that its Forward Test Year-end capital structure, as of December 31, 2018, be employed for rate-setting purposes. His specific recommendations provide NIPSCO's projected capitalization levels, corresponding capital structure ratios, and embedded cost of debt as of December 31, 2018. Pet. Ex. 13, Attach. 13-A, Sched. 2. He stated that to confirm the reasonableness of NIPSCO's Forward Test Year-end capital structure, he evaluated the actual and projected equity capitalization levels for the Combination Utility Group companies, as published by Value Line™, which are calculated on the basis of permanent capitalization and exclude short-term debt. He stated NIPSCO's proposed equity capitalization level, based on investor-supplied sources of capital, and stated as of December 31, 2018, is 57.88%, which is within the range of equity capitalization ratios anticipated for the Combination Utility Group companies, as reflected in near-term forecasts published by Value Line™. Mr. Rea testified the cost rate for common equity is 10.70%, which is the cost of equity he is recommending in this proceeding, and the cost rate for Long-Term Debt is 5.25%, which is based on NIPSCO's projected long-term debt outstanding at December 31, 2018.

Mr. Rea supported Adjustment CS 2-17 in the amount of $123,102,315 and Adjustment CS 2-18 in the amount of $289,416,820 to increase Long-Term Debt for the period ending December 31, 2017, and December 31, 2018, respectively. He testified these changes are based on the 2017 and 2018 budgeted debt issuances, retirements, and amortization of debt premiums and discounts.

Mr. Rea testified that in making his determination of an appropriate fair rate of return on the fair value of NIPSCO's rate base for its gas distribution operations, he adopted the same methodology the Commission employed in its Final Order in the Westfield Gas Corporation Cause No. 43624 where the Commission reduced the cost of equity by the prospective rate of inflation. *Westfield Gas Corp.,* Cause No. 43624, 2010 WL 1003185 (IURC Mar. 10, 2010). He testified that in this proceeding he determined that a reasonable estimate of the prospective rate of inflation is 1.99%, which is based upon the recent historical differential between the nominal yield on 30-year Treasury bonds and the yield on inflation-indexed Treasury bonds bearing the same maturity. He testified that after reducing NIPSCO's proposed cost of equity by the estimated prospective rate of inflation of 1.99%, he determined that an appropriate fair rate of return on the fair value of NIPSCO's gas distribution rate base property is 5.83%. Mr. Rea testified that the product of his 5.83% fair return on fair value estimate and the $2,442,131,404 fair value rate base would produce $142,376,261 of NOI. NIPSCO's proposed revenue requirement for purposes of setting rates in this proceeding includes a NOI of $99,941,966. Mr. Rea opined that from a fair value statutory policy perspective, NIPSCO's proposed rates in the instant proceeding are conservative.

N. **Amy Efland.** Ms. Efland, Manager of Demand Forecasting with NCSC, testified regarding weather normalization. Ms. Efland proposed an adjustment to unbilled Historic Base Period consumption to reflect the unbilled estimate that would have been made under normal weather conditions. She explained that gas rates include charges tied to consumption, and that such charges are developed by dividing required revenue by therms of consumption from the Historic Base Period. She noted that because these charges are dependent on consumption, variations in weather affect the costs allocated to each therm. She explained that calculating these charges based on a base or test year with abnormally high consumption would result in a lower allocation of costs to each therm consumed and that the gas utility will be unable to collect the revenue upon which rates were based when consumption returns to more normal. She concluded that the amount of gas energy consumed during the Historic Base Period is abnormally low and that the Historic Base Period does not reflect a representative level for ratemaking purposes.

Ms. Efland discussed the base load/temperature-sensitive load normalization procedure that was used to derive the weather normalized consumption and explained that NIPSCO's billing records for monthly customer count and therm sales were used together with National Weather Service Weather Stations data for temperatures and normal weather based on the 30-year average of 1987-2016. She stated actual heating degree days were less than normal by 11.4%. A normalization adjustment to increase usage by 72,907,353 therms or 7.5% of the annual volume for the adjusted rates was appropriate. She explained that the adjustment is a smaller percentage than the weather measure because base load is not adjusted as part of the calculation.

Ms. Efland explained the normalization of unbilled volume in the Historic Base Period is an estimate of the therms consumed during the month between the day the meters were read and the last day of the month. She stated that to normalize unbilled volume for the Historic Base Period, she applied the appropriate factors to the normal number of heating degree days in the unbilled period and the average number of days in the unbilled period.

Ms. Efland explained how Design Day consumption was derived and how it was allocated to rate classes. She also explained the forecast method used to derive the Forward Test Year customers and volume and proposed an adjustment to align the forecast with the definition of normal weather proposed for ratemaking purposes.

O. **Ronald J. Amen.** Mr. Amen, Director with Black & Veatch, sponsored the class cost of service study and rate design filed in this proceeding. He discussed the purpose of an allocated cost of service study ("ACOSS") and described the Black & Veatch Cost of Service Model used in conducting NIPSCO's gas cost of service studies. He explained that the purpose of an ACOSS is to determine what costs are incurred to serve the various classes of customers of the utility to provide the analyst with the data necessary to design cost-based rates.

Mr. Amen discussed the various principles of cost allocation, factors that influence the cost allocation framework, and the underlying methodology and basis used in NIPSCO's gas cost of service studies. He described the special studies employed to apportion the various categories of plant and O&M expenses to the respective customer classes. He testified to establish the cost responsibility of each customer class, a three-step analysis of the utility's total operating costs must be undertaken as follows: (i) cost functionalization; (ii) cost classification; and (iii) cost allocation of all the costs of the utility's system. The first step, cost functionalization, identifies and separates plant and expenses into specific categories based on the various characteristics of utility operation. NIPSCO's functional cost categories associated with gas service include: storage, transmission, distribution, and customer accounts and sales. The second step, cost classification, separates the functionalized plant and expenses into three cost defining characteristics as follows: (i) customer related; (ii) demand or capacity related; and (iii) commodity related. The final step is the cost allocation of all the costs of the utility's system. Costs are allocated by function and cost element to the individual customer or rate class. Costs typically are allocated on customer, demand, and commodity allocation factors. He stated the factors that can influence the cost allocation used to perform an ACOSS include the following: (i) the physical configuration of the utility's gas system; (ii) the availability of data within the utility; and (iii) the state regulatory policies and requirements applicable to the utility.

Mr. Amen presented the class-by-class rate of return results and corresponding revenue surpluses or deficiencies from NIPSCO's ACOSS, including a discussion of the resulting unit costs by class for customer, demand, and commodity related costs within the ACOSS. He testified there are three basic components in gas utility operations which govern cost behavior as follows: (i) extending distribution services to all customers entitled to be attached to the system; (ii) meeting the aggregate Design Day capacity requirements of all customers entitled to service on the Peak Day; and (iii) delivering volumes of natural gas to all customers either on a sales or transportation basis. These operational components have been identified for purposes of the ACOSS as Customer Costs, Demand Costs, and Commodity Costs. He explained that Customer Costs are incurred to extend service to and attach a customer to the distribution system, meter any electric usage, and maintain the customer's account. Customer Costs are largely a function of the number of customers served and continue to be incurred whether or not the customer uses any electricity. They may include capital costs associated with minimum size distribution systems, line transformers, services, meters, and customer billing and accounting expenses. He explained that Demand Costs are capacity related costs associated with a plant that is designed, installed, and operated to meet maximum hourly or daily gas flow requirements, such as transmission and distribution mains or more localized distribution facilities, which are designed to satisfy individual customer maximum demands. Capacity related costs are also a component of gas supply contracts, which are incurred to meet the utility's requirements for serving daily peak demands and the winter peaking season. He explained that Commodity Costs are those costs that vary with the throughput sold to, or transported for, customers. He stated that, for example, included in the instant study are commodity related costs such as compressor fuel, underground storage inventory or "working gas", and fuel related to storage injections or withdrawals, and LNG gasification. However, when, as here, a gas utility's cost of gas is not recovered through its base rates, very little of its remaining delivery service cost structure is commodity related.

Mr. Amen explained how the cost analyst establishes the cost and utility service relationships, what prompts the analyst to perform a special study, how you determine whether to directly assign costs to a particular customer or customer classes, the considerations relied upon in determining the cost allocation methodologies that are used to perform an ACOSS, and the key issues related to the allocation of demand-related costs within a cost of service study. He explained the three methodologies that form the foundation for the allocation process are as follows: (i) Peak Demand Allocations; (ii) Average and Excess Demand Allocations; and (iii) Non-Coincident Demand Allocations. Mr. Amen sponsored Petitioner's Exhibit No. 15, Attachment 15-C, providing the relevant load characteristics of NIPSCO's various customer groups and explained the implications of class load characteristics for purposes of determining the costs to serve utility customers.

Mr. Amen discussed revenue allocation and rate design principles, and the appropriate guidelines for use in evaluating class revenue levels and rate structures. He explained and supported the allocation of NIPSCO's revenue deficiency to the various rate schedules consistent with NIPSCO's class revenue mitigation objectives. He explained that when evaluating class revenue levels, the rate of return results show that rates charged to certain rate classes recover less than their indicated cost of service. Conversely, rates for other rate classes recover more than their indicated cost of service. By adjusting rates accordingly, class revenue levels can be brought closer to the indicated cost of service, resulting in class rates of return nearer the system average rate of return. Thus, adjusted rate levels will be more in line with the cost of providing service. He stated the classified costs, as allocated to each class of service within the ACOSS, provide useful cost information to determine the level of customer, demand, and commodity charges. He further explained how the classified costs can be used for rate design. Mr. Amen sponsored Petitioner's Exhibit No. 15, Attachment 15-F, providing a summary of NIPSCO's functionalized revenue requirement per unit of peak demand, annual throughput (commodity), and customer count for each rate class.

Mr. Amen stated that completely restructuring a utility's rates mechanistically to match the unit costs from the ACOSS is often not desirable due to the resulting adverse impact on certain customer classes, particularly for low-use low-load factor customers. However, the use of three-part rates has become more widely accepted as the unbundling of gas utility services evolved over the last decade or so and the sale of the gas commodity in a competitive market is distinguishable from utility delivery service. The unit costs provide useful information for the design of portions of tariff services, in particular for establishing cost-based customer charges. The unit costs also can be used to design demand charges where either demand metering is available or algorithm-based billing demands can be determined. Demand-based rates provide for a charge based upon the maximum demand imposed by a customer on the utility's system within a specified time period, which establishes both the utility's responsibility to serve and the customer's obligation to pay for that level of service. Mr. Amen described other considerations or criteria that should be used in the design of utility rates. He stated that utility rate design should recognize that rates must be just and reasonable and not cause undue discrimination. Thus, cross-subsidization within customer classes and customer bill impact considerations must be factored into the rate design process. Market conditions within the utility service territory with respect to the general economic environment and competitive fuel prices, where appropriate, could be a factor. Another important consideration is the financial stability of the utility. Toward this goal, it is generally an unsound ratemaking practice to recover a substantial portion of fixed costs, such as customer related costs, which bear no relationship to customer consumption patterns, in the volumetric portion of the rate structure. Recovery of fixed costs via volumetric rates adversely impacts earnings stability because the revenues generated from customers' volumetric use of gas can be extremely sensitive to weather patterns and changing consumption characteristics due to energy conservation efforts, among other factors. Recovery of utility fixed costs in volumetric rates sends uneconomic price signals to consumers that impede their ability to make well founded energy consumption decisions based on the actual costs of various types and levels of utility distribution service.

Mr. Amen testified that a reasonable balance between the various cost guidelines and other criteria must be established in the process of designing rates, which consists of both the recovery of the revenue requirement from among the various customer classes and the determination of rate structures within tariff schedules. Economic, social, historical, and regulatory policy considerations can impact the rate design process. Both quantitative and qualitative factors must be considered in reaching a final rate design. Thus, it is necessary to allow the rate design process to be influenced by judgmental evaluations.

Mr. Amen discussed NIPSCO's rate design proposals. Proposed rate levels by class were presented as well as bill impacts by class. Mr. Amen described the proposed revenue requirement and revenue allocation methodology employed. He stated NIPSCO has used a total distribution revenue requirement of $458,722,234, exclusive of gas costs. Net of miscellaneous other revenue of $6,834,880, the total non-gas rate schedule revenue requirement is $451,887,354. He stated the results of the ACOSS have been used in establishing the class-by-class revenue responsibility levels at NIPSCO's proposed revenue requirement. He described the approach followed to apportion the current revenue responsibility to NIPSCO's various rate schedules. He stated the allocation of revenues among rate schedules consists of deriving a reasonable balance between various guidelines and criteria that relate to the design of utility rates. The following criteria were considered in this process: (i) cost of service results; (ii) class contribution to present revenue levels and the resulting inter-class subsidies; (iii) customer bill impacts; and (iv) NIPSCO's belief that while movement toward parity with the system-wide rate of return is the ultimate goal, moderation should be employed in accomplishing that goal. Mr. Amen sponsored Petitioner's Exhibit No. 15, Attachment 15-F, showing the proposed distribution of the proposed margin revenue increase of $143,471,797 among the rate schedules. He testified that after evaluating the criteria for each of NIPSCO's proposed rate schedules, adjustments were made to class revenue levels with the intent to close the deficiency or surplus gaps between current class returns and uniform returns by class at the system average return of 6.74% at proposed rates, with no class receiving a revenue decrease.

Mr. Amen described NIPSCO's proposed rate structure and rate levels by customer class. He sponsored Petitioner's Exhibit No. 15, Attachment 15-H, showing the detailed calculations for each rate component of each rate. He stated the targeted total rate schedule revenue will be achieved using the proposed rates and volumes. He testified the proposed rates include increases to the existing monthly customer charges, which reflect NIPSCO's intention to move to a greater recovery of fixed distribution costs in fixed charges.

Mr. Amen explained how NIPSCO's proposed increase to the customer charge will impact the average residential customer's gas bills. He stated a higher customer charge provides increased bill stability for customers as well as increased revenue stability for NIPSCO. He sponsored Petitioner's Exhibit No. 15, Attachment 15-I, showing the monthly bill impact for a typical gas customer. The exhibit presents monthly and annual bills for an average residential customer using 824 therms per year, at the proposed revenue level for the class, comparing the proposed $19.50 customer charge with retaining the current $11.00 charge. He also provided a depiction of a typical gas customer's monthly bills (for both gas costs and margin) under three different levels of customer charge as follows: (i) the $11.00 current monthly customer charge, (ii) NIPSCO's $19.50 proposal, and (iii) the full $31.08 SFV rate. He testified that the most stable monthly bills are produced by the full SFV rate, and the least stable are produced by the current customer charge. He indicated this is the case because under the SFV rate, customers pay the full margin through a fixed customer charge each month, regardless of gas usage. By contrast, under the current monthly charge scenario, customers pay substantially more of the margin in the winter and less in the summer. As a result, the average bill in January is nearly $10.00 higher under the current monthly customer charge than under NIPSCO's proposed $19.50 charge.

Mr. Amen testified NIPSCO's higher customer charge is fair because it increases the portion of the non-volumetric margin recovered through the non-volumetric customer charge. With a higher customer charge, a higher percentage of the non-volumetric costs are paid in equal shares. For example, each customer under an SFV rate design pays the full share of the non-volumetric cost allocated to him or her. Under the SFV rate design, each customer would not: (i) overpay or underpay his share of the non-gas costs based on his relative-to-average consumption; (ii) pay a higher delivery charge in the winter than in the summer; or (iii) pay a higher delivery charge during a cold spell. Under the continuation of the current customer charge, current customers who have very little annual usage (such as owners of summer homes) can pay less than 35% of their allocated fixed costs, while very high use customers can pay 200%. This is because a customer charge of $11.00 is substantially less than the $31.08 cost of service allocation of non-volumetric costs.

Mr. Amen testified NIPSCO introduced a Demand Charge for the two Transport & Transport Balancing Services (Rates 428 and 438). He stated that the use of three-part rates by gas utilities is more prevalent in today's competitive gas marketplace. Demand charges reduce intra-class subsidies by lowering the average cost of utility service for high load factor customers and by encouraging efficient use of the distribution system. He stated that NIPSCO proposes to establish the initial Demand Charges for these commercial and industrial ("C&I") rate schedules to recover approximately 25% of fixed demand related costs of providing distribution service to these rate schedules. The demand billing determinant for customers served under these rates will be determined at the average daily usage during the three billing months of December 2015 through February 2016.

Mr. Amen sponsored Petitioner's Exhibit No. 15, Attachment 15-J, providing bill comparisons for the C&I rate classes that result from NIPSCO's rate design proposal. He testified that at the proposed levels, the customer and demand based charges result in a more substantial recovery of the overall fixed costs for the Residential and C&I customer classes. He stated that more than $238 million of fixed, customer, and demand related costs representing approximately 54% of the total fixed costs of NIPSCO will be recovered through non-volumetric rates for the various classes of gas distribution service.

P. Curt A. Westerhausen. Mr. Westerhausen, Director of Regulatory with NCSC, explained that NIPSCO intended for its tariff to meet the needs of its customers. NIPSCO retained its existing service structure in part because it was developed collaboratively with its stakeholders during negotiations in NIPSCO's last base rate proceeding in Cause No. 43894. Mr. Westerhausen's testimony includes a discussion of billing rates beginning January 1, 2017 and ending December 31, 2017 ("Forecasted 2017").

Mr. Westerhausen described NIPSCO's currently effective IURC Gas Service Tariff, Original Volume No. 7 (the "Current Tariff"), including the programs and services that were approved under an ARP. He testified that with the exception of updates for consistent use of defined terms (namely, capitalization of terms) and consistent presentation and formatting (i.e., referencing Appendix A instead of listing specific applicable Riders), the addition of Rule 16 – Capacity Release Sharing Mechanism (because there was no reference in its Current Tariff), NIPSCO is not proposing modifications to its current ARP. Mr. Westerhausen described NIPSCO's proposed IURC Gas Service Tariff, Original Volume No. 8, including the Schedule of Rates, Riders and General Rules and Regulations ("Proposed Tariff"). He explained how the Proposed Tariff differs from the Current Tariff. He noted that current rates have been updated to reflect NIPSCO's proposed revenue requirement allocated to the rate classes through the ACOSS and mitigation model.

Mr. Westerhausen summarized each of NIPSCO's Proposed Rates, including a discussion of the components of each rate, an overview of the changes made to each, and the rationale for making the changes. He stated NIPSCO proposes to add Rider 189 – Pipeline Burner Tip Balancing Rider as an optional firm service available to Rate 128 Category A Customers receiving gas service from NIPSCO whose gas requirements during the most recent calendar year average at least 3,000 Dth per day and have the propensity for large changes in intraday usage as part of normal business operations. He explained that a customer will contract Pipeline Burner Tip Balancing service with Company approved upstream interconnected pipeline(s), and that NIPSCO may require Rate 128 customers to take balancing services under Rider 189 in some circumstances if NIPSCO is unable to balance the customer's load under traditional methods. Mr. Westerhausen also discussed NIPSCO's proposal to discontinue Rider 487 – Daily Imbalance Cash-Out Provision. He explained that during the review of the Current Tariff, NIPSCO determined that the Daily Imbalance Cash-Out Provision in Rider 487 was already included in Rate 445, making Rider 487 unnecessary as a stand-alone rider.

In addition to his discussion of each tariff rate, Mr. Westerhausen summarized the provisions of each of NIPSCO's General Rules and Regulations and provided detailed support for NIPSCO's proposed changes. These included the revision of Rule 13 and the updating of Miscellaneous and Non-Recurring Charges under Rule 17. He also sponsored NIPSCO's proposed standard agreement for gas service for Rates 125, 128, and 138, along with NIPSCO's Rate Release Form, which is documentation of a customer's request to change rates.

Mr. Westerhausen sponsored Petitioner's Exhibit No. 16, Attachment 16-G that provided the following: (i) a summary of the Historic Base Period, the Forecasted 2017, and Forward Test Year; (ii) adjusted billing determinants for the Historic Base Year by number of bills, delivery in therms per rate and per block, the weather normalization Adjustment REV 1A-16, and the 2016 adjusted billing determinants; (iii) the 2016 adjusted billing determinants, the increase or decrease to Forecasted 2017, the Forecasted 2017 billing determinants, Forecasted 2017 billing determinants, the increase or decrease to Forward Test Year, customer migration Adjustment REV 1B-18R, weather Adjustment REV 1A-18R, and customer count Adjustment REV 4B-18R; and (iv) the 2018 adjusted projected billing determinants that were utilized for the development of the proposed rate design. He also presented detailed descriptions and support for a series of proposed pro forma adjustments.

8. **NIPSCO's Supplemental Direct Testimony.** NIPSCO submitted supplemental direct testimony and attachments to address changes to its case-in-chief that were required by the enactment of the 2017 Tax Act signed into law on December 22, 2017.

A. **Michael D. McCuen.** Mr. McCuen testified, presenting and supporting changes in his direct testimony for federal and state income tax expense and taxes other than income tax expense as required by the enactment of the 2017 Tax Act. He testified 2017 Tax Act reduced the U.S. corporate tax rate from a maximum rate of 35% to a flat rate of 21% which has an impact on NIPSCO's proposed revenue requirements. He explained how that reduction affects accumulated deferred taxes. He testified GAAP principles require the ADIT to reflect the value of the tax expected to be paid. NIPSCO expects the temporary differences giving rise to the ADIT to reverse at the new corporate rate of 21%; therefore, he re-measured the ADIT from 35% to 21%. As an effect of the re-measurement, NIPSCO identified excess deferred taxes on its balance sheet.

Mr. McCuen explained how the excess deferred taxes will be returned to customers. He testified NIPSCO proposes to follow the Commission's prior precedent and pass back all excess deferred taxes using ARAM. He noted that other small changes were made to the Deficiency for Flow-Through of AFUDC Equity, Non-Deductible Expenses, and Muncie Tax Remand. Mr. McCuen testified deferred tax accounts (190, 282, and 283), along with related regulatory assets and liabilities (182 and 254), which are considered adjustments to ADIT, are included in the WACC. He stated the re-measuring of NIPSCO's accumulated deferred taxes has no net impact on NIPSCO's current WACC because the reduction in NIPSCO's deferred tax accounts (190, 282, and 283) are equally offset by regulatory assets and liabilities (182 and 254). He testified that the pass back of excess deferred taxes reduces the overall Deferred Income Taxes included in WACC. He stated this nominal amount had not been updated for this filing, but when NIPSCO's two-step rate increase is implemented, the WACC will be updated. Mr. McCuen testified there is no change to the calculation of the URT; however, as the proposed revenue requirements change due to the impacts of the 2017 Tax Act, the URT will be adjusted correspondingly.

Mr. McCuen testified the 2017 Tax Act includes a provision for 100% expensing of assets placed in-service between September 27, 2017 and December 31, 2017. He stated this 100% expensing reduces federal tax basis in those assets, which is the starting point for the calculation of Indiana property tax. He testified that using the 2018 forecasted numbers and applying the 100% expensing change, NIPSCO estimated a property tax savings of $111,814. Additionally, the 2018 expense is based on NIPSCO's ending December 31, 2017 property amounts. These amounts were estimated for the 2018 forecast. Any true-up to the actual December 31, 2017 property amounts will have an impact on the overall property tax amount.

Mr. McCuen testified the 2017 Tax Act necessitates specific accounting treatment requests in this Cause. He stated NIPSCO used an estimate, the Commission approved composite depreciation rate of 2.18%, to calculate the 2018 amortization of excess deferred taxes. In this case, NIPSCO is requesting that the Commission authorize NIPSCO to defer as a regulatory asset or regulatory liability the difference between the actual excess ADIT amortization and the amount included in rates beginning on the date rates are implemented in this proceeding until NIPSCO's two-step rate increase is implemented. He stated to the extent that actual annual amortization differs from the estimated amount, the amortization of the non-normalized excess ADIT will be increased or decreased to ensure that the total amortization of normalized and non-normalized excess ADIT is equal to the filing. He stated this accounting treatment is necessary to ensure NIPSCO remains in compliance with tax normalization requirements and avoids a tax normalization violation.

B. <u>June M. Konold</u>. Ms. Konold testified, explaining and supporting the changes to NIPSCO's proposed revenue requirements in this proceeding stemming from the 2017 Tax Act. She sponsored Petitioner's Exhibit No. 3-SD, Attachments 3-A-SD through Attachments 3-D-SD, representing an update to the originally filed attachments to reflect the impact of tax reform.

Ms. Konold explained some of the key provisions for NIPSCO's proposed revenue requirement that were impacted by the 2017 Tax Act. She testified that the 2017 Tax Act reduces the U.S. corporate tax rate from a maximum rate of 35% to a flat rate of 21%, thus reducing NIPSCO's projected federal income tax expense for 2018 and beyond. She explained that the 2017 Tax Act also includes provisions requiring normalization of certain excess tax reserves associated with public utility property – namely, the difference between the utility's deferred taxes at previous 35% tax rates versus the 21% tax rate included in the Act. She noted that while the 2017 Tax Act limits business interest expense, this limitation does not apply to business interest expense that is properly allocable to the trade or business of furnishing or selling utility services (including gas, electricity, etc.) through a local distribution system if the rates for such are subject to rate regulation.

Ms. Konold testified that the 2017 Tax Act extends and modifies the use of "bonus deprecation" (temporary 100% expensing for certain business assets), but excludes from the provisions of "bonus depreciation" any property used in providing certain utility services (including gas and electricity) if the rates for those services are regulated. She explained that the 2017 Tax Act does the following: (i) repeals the alternative minimum corporate tax; (ii) limits the net operating loss deduction for a given year to 80% of taxable income for losses arising in tax years after 2017; (iii) repeals the current carryback provisions for net operating losses arising in tax years after 2017; and (iv) provides for the indefinite carry forward of net operating losses arising in tax years after 2017.

Ms. Konold testified the 2017 Tax Act reduces NIPSCO's proposed revenue requirements in this case by $25,569,976 from $775,629,855 (as originally filed) to $750,059,879. She also explained that while the 2017 Tax Act reduces the overall proposed revenue requirement, there is no change to NIPSCO's NOI. She testified this change in revenue requirements primarily results from the change in federal income tax expense resulting from the new lower federal tax rate. The additional changes in NIPSCO's proposed revenue requirements result from the change in revenues produced by the change in tax rate (specifically, uncollectible expenses, the public utility fee, and URT). She stated an updated revenue conversion factor was applied to the TDSIC Regulatory Asset, resulting in a decrease to amortization expense. Finally, she explained the change to the 2017 100% expensing provision results in a decrease to property tax expense and a decrease to revenue requirements.

Ms. Konold testified the 2017 Tax Act's reduction in the federal income tax rate to 21% reduces NIPSCO's pro forma federal and state taxes based on proposed rates from $47,722,811 to $23,582,590, and that the reduction in corporate tax rate decreases the gross revenue conversion factor to 72.934%, which affects NIPSCO's calculation of revenues. She noted that the tax rate reduction does not impact NIPSCO's overall WACC today because the reduction in projected deferred tax balances resulting from the lower federal tax rate is offset by a change in the regulatory assets and liabilities, both of which are included in NIPSCO's WACC calculation. She explained that that when NIPSCO's two-step rate increase is implemented, the WACC at that time will be used.

Ms. Konold testified there are a few additional smaller impacts, relating to uncollectible expenses (which will change as overall revenues change); property taxes (which will decrease due to the 100% expensing provision in 2017, but increases after that due to the removal of bonus depreciation in 2018 and 2019); and URT (which will change as the overall revenues change). She said NIPSCO is not proposing a change to the 2018 pro forma revenues at current rates in this submission. NIPSCO is continuing to review and analyze the impact of the 2017 Tax Act on current rates and anticipates providing an update to the pro forma revenues at current rates as part of its rebuttal testimony.

C. <u>Ronald J. Amen</u>. Mr. Amen testified regarding the changes in NIPSCO's cost of service study model resulting from the 2017 Tax Act impact on the revenue requirement. He discussed the results of the cost of service study model with NIPSCO's new revenue requirement, the derivation of the proposed rates, and the impact on customers.

Mr. Amen testified that changes to the revenue requirement resulting from the 2017 Tax Act were made in the Expenses at Current Rates for Amortization and Depreciation Expense, Taxes Other Than Income Taxes, Income Taxes, and Uncollectible Accounts Expense. He stated the impact of those expense changes on NIPSCO's Current Operating Income was an increase from $13,846,221 to $13,951,679.

Mr. Amen testified NIPSCO's revised revenue requirement is $433,152,258, and the proposed rate schedule margin is $426,317,378. He stated no changes were made to the pro forma class revenues at current rates.

Mr. Amen described NIPSCO's proposed distribution of the rate schedule margin revenue increase among the rate schedules and the respective percentage increases by class. He stated the approach to apportioning the margin revenue increase to the respective rate classes remains the same as previously proposed. Adjustments were made to class revenue levels with the intent to close the deficiency or surplus gaps between current class returns and uniform returns by class at the system average return of 6.74% at proposed rates, with no class receiving a revenue decrease. Mr. Amen explained the class-by-class results of the apportionment of the revenue increase related to the respective classes' relationship to parity.

Mr. Amen testified the changes to the revenue requirement that resulted from the 2017 Tax Act are included in the ACOSS under the alternative costing methodology. He stated that with the exception of Rate 134, which did not receive a class revenue increase in NIPSCO's pre-filed direct case, the volumetric Delivery Charges in Rates 111, 115, 121, and 125 were reduced to ensure the proposed rates would match the proposed total distribution margin for each class. Similarly, the Demand Charges and volumetric Transportation Charges in Rates 128 and 138 were reduced. He stated the average monthly bill impact for a typical Residential gas customer is $8.65, a decrease from the $10.35 monthly bill impact from the presentation in NIPSCO's pre-filed direct testimony. He also provided bill comparisons at various ranges of consumption levels for Residential customers and bill comparisons at various ranges of consumption levels for C&I Rates 115, 121, and 125.

9. <u>OUCC's Case-in-Chief.</u>

A. <u>Mark H. Grosskopf</u>. Mr. Grosskopf, Senior Utility Analyst, sponsored testimony that discussed the OUCC's proposed adjustments to NIPSCO's revenue requirements, amortization expenses, taxes other than income taxes, and state and federal income taxes. He also discussed Petitioner's proposed phase-in to update rate base methodology, TDSIC regulatory assets, and depreciation expense. He recommended the Commission reject Petitioner's proposal to use its fair value rate base in the GCA earnings test. Mr. Grosskopf explained that the OUCC's accounting schedules incorporated NIPSCO's Future Test Year ending December 31, 2018, and its Historic Base Period ending December 31, 2016, showing NIPSCO's gas operations results for this period. Mr. Grosskopf recommended that Petitioner's pro forma revenue requirement be reduced to $69,009,348, resulting in an increase in gross margin of 21.60%.

Mr. Grosskopf testified that the OUCC reviewed the entirety of NIPSCO's proposal and recommended approval of a large number of proposed adjustments.[19] He noted that the OUCC was in agreement with NIPSCO's methodology in calculating the public utility fee and URT. The changes to NIPSCO's calculations reflected in the OUCC's schedules result from the OUCC's proposed changes in pro forma revenues.

[19] Beginning on page 6 of his testimony, Mr. Grosskopf provides a list of NIPSCO's proposed adjustments that the OUCC supports.

Mr. Grosskopf testified that the OUCC did not dispute NIPSCO's methodology in calculating its pro forma federal and state income tax adjustments based on pro forma present rates, other than revisions related to Petitioner's supplemental filing adjusting federal income tax calculations. He testified that NIPSCO used a 35% federal income tax rate to calculate its pro forma adjustment in its case-in-chief, but as a result of the 2017 Tax Act, the federal income tax rate decreased to 21% effective January 1, 2018. NIPSCO filed supplemental testimony addressing changes as a result of the 2017 Tax Act on January 26, 2018, which included reducing its tax expense based on the new 21% corporate income tax rate. He explained Pub. Ex 1, Attach. MHG-1, Sched. 4, at 3 shows a revised federal tax expense using the 21% tax rate and a new adjustment to the pro forma federal income tax expense reflected as "2018 Tax Reform FT Change." He explained that the tax calculation also incorporates NIPSCO's revised adjustments to pro forma federal income tax expense for Deficiency for Flow-Through of AFUDC Equity, Non-Deductible Expenses, and Muncie Remand Method. He testified that all other changes to NIPSCO's federal and state income tax calculations are a result of changes to other pro forma proposed revenue requirements.

Mr. Grosskopf testified that the OUCC reviewed NIPSCO's actual rate base as of December 31, 2016, and its forecasted rate base through the December 31, 2018 Future Test Year and recommended no additional adjustments to the proposed forecasted rate base. He also explained the parties' competing positions concerning the update of rate base as part of the implementation of rates. He summarized the OUCC's position about the relationship between rate base, TDSIC assets, and NIPSCO's current and future seven-year plans as discussed by OUCC witness Rutter.

Mr. Grosskopf was critical of NIPSCO's proposal to calculate its GCA earnings test on fair value rather than original cost basis. He testified that he found that proposal to be problematic. The combination of the statutory earnings bank, the ability to update the authorized NOI under the TDSIC mechanism, and NIPSCO's proposed FMCA provide NIPSCO with insulation against increases in costs. He noted that the opportunity to earn a fair return means opportunity, not guarantee, and that NIPSCO also has the ability to pursue cost containment. The incentive to contain costs would be diminished by setting NIPSCO's NOI based on a fair value rate base while its base rates are set based on an original cost rate base. He concluded that basing the GCA NOI on a fair value rate base is an inappropriate means to cushion the utility against a perceived, potential lack of cost recovery to protect the utility's retained income, and the fair value rate base approach should be rejected.

Mr. Grosskopf testified that further adjustments to depreciation expense other than those proposed by NIPSCO are not needed. NIPSCO's depreciation expense is reflective of the new depreciation rates in NIPSCO's Depreciation Study. He explained that NIPSCO's depreciation expense adjustment also reflects elimination of the depreciation credit approved in NIPSCO's last rate case. A combination of new depreciation rates and elimination of the depreciation credit, in addition to a substantial increase in rate base over the past several years, yielded a significant increase in depreciation expense. He noted that depreciation expense will be updated to the actual expense to coincide with the actual utility plant in-service balance as of December 31, 2018, in the compliance submitted by NIPSCO to set Step Two rates.

Mr. Grosskopf indicated that his analysis did not reveal any deficiencies in the annual amortization rates used to calculate gas plant assets or common assets amortization expenses budgeted by NIPSCO. His schedules incorporate his adjustment to NIPSCO's amortization of its TDSIC regulatory asset and rate case expense, as sponsored by OUCC witness Larsen. The OUCC proposed amortization of both the TDSIC regulatory asset and rate case expense over seven years, resulting in a reduction in amortization expense from the four-year rate of $7,334,333 annually to a seven-year rate of $3,705,170 annually.

With respect to property tax expense, Mr. Grosskopf testified that the calculation is based on a 2017 tax return where taxes are not due until 2018, giving a current and relatively accurate pro forma expense amount. He explained that NIPSCO adjusted its property tax expense in its January 26, 2018 supplemental testimony, which addressed changes to NIPSCO's case-in-chief as a result of the 2017 Tax Act. Mr. Grosskopf did not dispute NIPSCO's revised property tax calculation. Similarly, he concluded that NIPSCO correctly applied the 21% tax rate in its supplemental filing and had also applied small changes to certain adjustments applied to income tax expense, such as Deficiency for Flow-Through of AFUDC Equity, Non-Deductible Expenses, and Muncie Remand Method.

Mr. Grosskopf recommended that NIPSCO refund the current overpayment of federal income tax (at 35% vs. the current 21% corporate rate) over the same period in which it is being collected, likely to be six to nine months after January 1, 2018. Mr. Grosskopf noted that NIPSCO's testimony was silent on the over-collection of tax expense in its current base rates.

Mr. Grosskopf also addressed how the change in tax law affects deferred taxes in the capital structure. He explained that the current deferred taxes in the capital structure are based on a 35% tax rate, but that NIPSCO paid less taxes using accelerated depreciation resulting in the difference of tax depreciation to book depreciation that is insufficient to offset the deferred tax liability created with a 35% tax rate. The difference is excess deferred tax liability, or excess deferred income tax ("EDIT") that had been "re-measured" by NIPSCO to identify the EDIT to be returned to customers. Mr. Grosskopf testified that for EDIT that is considered "protected," the 2017 Tax Act requires the reduction of the excess tax liability over the remaining regulatory life of the property that gave rise to the reserve for deferred taxes. He explained that the amortization of protected EDIT over the remaining life of the assets is the mechanism by which ratepayers are refunded the excess deferred tax liability. But NIPSCO proposed to amortize all EDIT, not just the protected excess tax liability over 46 years based on NIPSCO's "composite" depreciation rate of 2.18%.

Mr. Grosskopf disagreed with NIPSCO's proposed treatment of ADIT for two reasons. First, he explained that using NIPSCO's 2.18% depreciation rate as the basis to amortize EDIT does not comply with ARAM as required by the 2017 Tax Act. Second, he explained that the amortization of unprotected property and non-property EDIT over the same period as that for protected EDIT ignores the distinctly different circumstances that created each balance. It deprives ratepayers of the Commission's discretion as it relates to the amortization of the unprotected balance. He testified that the 2.18% used by NIPSCO is an average rate and not a composite rate. This is an important distinction because the 2017 Tax Act allows a utility to use an alternative method to amortize EDIT only if the utility was required to use an average life or composite rate by a regulatory agency. The utility's books and records do not contain data necessary to apply the

ARAM. He contended that NIPSCO must use ARAM. NIPSCO cannot make use of an alternative method because its Depreciation Study assigns a calculated annual accrual rate to each utility plant account, using the remaining lives of its utility property and those annual accrual rates in each plant account. He testified that NIPSCO incorrectly equated "the remaining lives of the property" with the 2.18% average annual accrual rate, yielding its proposed 46-year amortization period. He explained that NIPSCO's 2.18% average accrual rate includes some fully depreciated plant items with no future accrual, thereby distorting NIPSCO's proposed average remaining life. He testified that he used future accruals from NIPSCO's Depreciation Study divided by the calculated accrual amount to calculate the remaining useful life of total depreciable plant to be 42.3 years, representing his calculation of the maximum amortization period for protected EDIT.

Mr. Grosskopf recommended rejection of NIPSCO's EDIT, whether categorized as protected property, unprotected property, or unprotected non-property. He explained that unprotected non-property EDIT is derived from tax differences related to tax adjustments that are not related to depreciation on utility property. Unprotected property EDIT results from expense deductions available for tax purposes for costs that were capitalized for book purposes unrelated to the depreciation of utility property. He explained that the amortization of unprotected property and non-property EDIT is not tied directly to the remaining lives of the assets that gave rise to the deferred tax. The 2017 Tax Act does not require a specific amortization period for unprotected property and non-property EDIT, providing the Commission with discretion to determine an appropriate amortization period. Mr. Grosskopf recommended the amortization of unprotected property and unprotected non-property over seven years.

Given the uncertainty surrounding the income tax issues, Mr. Grosskopf recommended that remaining issues be addressed in Phase Two of the Commission's tax investigation in Cause No. 45032, prior to the Step Two rate update encompassing balances as of December 31, 2018.

B. Isabelle L. Gordon. Ms. Gordon, Utility Analyst, disagreed with NIPSCO's pro forma adjustments to 2017 and 2018 interruptible sales revenue. She stated that although NIPSCO provided supporting documentation in the work papers accompanying its filing indicating it anticipates that customers will use or are using Rate 434 Interruptible Service in both 2017 and 2018, NIPSCO did not include revenue from this rate class in its budget for 2017 or 2018. Instead, NIPSCO asserts interruptible sales are included in the transportation budgets for commercial and small industrial customers. NIPSCO indicated transportation revenues would be relatively the same as the Historic Base Period. Additionally, NIPSCO makes a ratemaking adjustment to set transportation customers' revenues to Historic Base Period levels. Included in NIPSCO's transportation revenue budget are CHOICE revenues, which NIPSCO expects to remain relatively flat as well. NIPSCO demonstrates that expectation by recognizing the necessity of reclassifying amounts incorrectly attributed to CHOICE customers by NIPSCO. Pet. Ex. 3, Attach. 3-B, 3-C, and 3-D, Adjust. REV 4A-18R. The expectations discussed above result in a $608,213 increase over the Historic Base Period for a Forward Test Year transportation revenue of $64,214,042.

Ms. Gordon disagreed with NIPSCO's adjusted transportation revenues. She stated that while NIPSCO's Forward Test Year transportation revenue budget is reasonable in light of its Historic Base Period actuals, the transportation revenue budget does not include interruptible sales revenue, as NIPSCO asserts in response to discovery. Historic Base Period commercial interruptible sales and small industrial interruptible sales sum to $4,012,115. NIPSCO includes that amount in the broad category of Historic Base Period retail revenue rather than the broad category of transportation revenue. NIPSCO's Forward Test Year interruptible sales revenue is reasonably calculated to be equal to its Historic Base Period interruptible sales revenue. Based upon the historic amounts of interruptible sales revenue, it would be reasonable for the 2017 and 2018 pro forma budget to match 2016 actuals. Because NIPSCO has not increased its Forward Test Year transportation revenue budget to adequately account for interruptible sales revenue, she adjusted retail revenue for 2017 and 2018. She made an adjustment increasing NIPSCO's Forward Test Year retail revenue by $4,012,115 to reflect the corrected interruptible sales budget.

Ms. Gordon agreed with NIPSCO's budget calculations of Non-Sufficient Funds ("NSF") revenue and reconnect fees. She disagreed with NIPSCO's budget calculation of CHOICE fees. She stated NIPSCO's NSF revenues and reconnect fee 2017 and 2018 budgets are based on a four-year average, but the CHOICE fees budget is based only on 2016 data. She stated that in discovery, NIPSCO explained, "In some cases . . . a longer period is chosen to calculate an average because these are susceptible to fluctuations in customer usage. The longer period evens out those fluctuations." NIPSCO provided data showing its 2012 through 2015 CHOICE fees, which demonstrate this revenue category is susceptible to fluctuations. This shows one year is an insufficient budgeting basis. She therefore increased NIPSCO's pro forma CHOICE fees to reflect the four-year average. She increased NIPSCO's pro forma CHOICE fees by $194,944 to arrive at a new pro forma miscellaneous service revenue of $1,930,545. Comparing this amount to the Historic Base Period miscellaneous service revenue amount of $1,648,954 results in a total increase to miscellaneous service revenue of $281,591.

Ms. Gordon testified her review showed NIPSCO omitted from its adjustment several charitable contributions. She stated NIPSCO omitted 11 items listed as charitable contributions in Accounts 90300000 and 92100000. These payments include sponsorships, commemorative gifts and programs, and equipment replacement. These payments and contributions are not necessary to the provision of natural gas utility service and do not benefit ratepayers at large. As such, it would be inappropriate for NIPSCO to recover these expenses from ratepayers. In calculating the OUCC's proposed revenue requirement in this Cause, she removed these expenses from NIPSCO's O&M expense. She increased NIPSCO's disallowed expense by $7,208 from $136,133 to $143,341 for the Historic Base Period. After making pro forma adjustments to 2017 and 2018 for inflation, the total decrease to O&M Expense is $149,132.

Ms. Gordon testified NIPSCO included advertising expenses that are not appropriate for recovery. She stated NIPSCO included items as "allowable advertisements" that neither benefit ratepayers nor promote the public safety of ratepayers. She removed an additional $73,829 of disallowed advertising expense from the Historic Base Period. After adjusting for inflation in 2017 and 2018, her adjustment to disallow advertising expense is a decrease of $76,812. Her adjustment results in a decrease to O&M expenses of $76,812 for total reduction to advertising expense of $114,544.

Ms. Gordon testified she agreed with the changes NIPSCO proposed to eliminate lobbying expenses, but there are additional lobbying expenses that must be eliminated from base rates. The lobbying expenses allocated to NIPSCO are part of the membership paid to Northwest Indiana Forum and total $659. Additionally, due to incorrectly allocated membership fees, NIPSCO overstated NIPSCO allowable expenses by a total of $34,440. These expenses should have been allocated to NIPSCO Electric. Her adjustment for these disallowed expenses results in 2017 expenses of $401,128. Adjusting for inflation in 2018, the total expense to be disallowed from the revenue requirement is $444,127, which is a $35,801 increase. She noted that NIPSCO notified in discovery that it intends to address in its rebuttal testimony the error relating to lobbying expenses and membership allocation errors.

C. **Mark P. Dermody.** Mr. Dermody, Utility Analyst, disagreed with NIPSCO's pro forma adjustment OM 2B for the 2017 Budget Period relating to an increase in vegetation clearing activity based on shortening the clearing cycle from 40 to 15 years and the Forward Test Year based on inflation. He stated there is no requirement to shorten the right-of-way clearing cycle. Mr. Dermody stated NIPSCO has not provided sufficient support to indicate that vegetation has or will cause issues with the maintenance, inspection, or safety or cause damage to pipelines. Mr. Dermody testified that while he agreed with the methodology NIPSCO used to calculate inflation for the Forward Test Year, he did not agree with the adjustment 2017 Budget Period amount; therefore, there is no need to increase this expense. He reduced Adjustment OM 2B to match its actual right-of-way clearing expense for the 12 months ending December 31, 2016. He adjusted this amount for inflation, resulting in an increase of $17,264 in the 2017 Budget Period and an increase of $17,610 in the Future Test Year for a total cost of $898,090.

Mr. Dermody disagreed with NIPSCO's proposed inclusion of a 30% contingency cost to Transmission Risk Modeling, in addition to the program cost in Adjustment OM 2D. He also recommended NIPSCO seek recovery of the costs for this program in the Gas FMCA Proceeding. He removed the cost of this 30% contingency to recalculate the program cost of $235,039. He stated that the program appears to be federally mandated. He stated it appears NIPSCO is conducting this risk modeling because it believes it is required to do so by federal rules; therefore, as a ratepayer protection against the embedding of preliminary cost estimates with contingencies in base rates, he recommended NIPSCO seek cost recovery for these expenses in its Gas FMCA Proceeding. He stated tracker recovery of these costs will allow the Commission, NIPSCO, and the OUCC to ensure ratepayers are paying for the actual costs of the program instead of an inaccurate estimate. He recommended removal of Adjustment OM 2D to ensure that expenses for this program, if approved, can be properly tracked in a FMCA filing.

Mr. Dermody disagreed with NIPSCO's Adjustment OM 2F for legacy cross-bore expenses and recommended NIPSCO seek approval of the costs for this program in its pending Gas FMCA Proceeding. He stated NIPSCO has requested additional expenses for this program in its Gas FMCA Proceeding. Recovering expenses for this project in two separate causes creates needless confusion and makes it harder to determine the actual cost of the project. He stated expenses for employees and total camera costs are included in this Cause, but additional costs for this program are included in the Gas FMCA Proceeding. He stated that by placing all of the expenses for this program in NIPSCO's FMCA filing, the expenses of the project, if approved, can be comprehensively reviewed and tracked. This will also allow the Commission, NIPSCO, and the OUCC to ensure ratepayers are not charged twice for the same expenses. He recommended removal of Adjustment OM 2F to ensure that expenses for the legacy cross-bore expenses, if approved, can be properly tracked in a FMCA filing.

Mr. Dermody disagreed with NIPSCO's Adjustment OM 2H because he has concerns that the estimate is not accurate. First, according to NIPSCO, the hours of work used in determining the estimate are based on the hours needed in a previous project, but NIPSCO does not explain what the previous project is, how the previous project is related, or why the estimated hours would be similar. Without a reasonable explanation for why this unidentified project serves as an appropriate basis to estimate the MAOP distribution project costs, Mr. Dermody testified that NIPSCO's cost estimate cannot be relied upon. Second, NIPSCO's cost estimate for the MAOP distribution project is not in line with its actual expenses for the project in 2017. He recommended removal of Adjustment OM 2H.

Mr. Dermody disagreed with NIPSCO's Adjustment OM 2I because he has concerns that the estimate is not accurate because a portion of the estimated annual maintenance costs for this program is based on the number of miles of transmission pipeline. He believed the percent of transmission miles appear to have no correlation with the percent of actual costs or the percent of estimated costs. Additionally, NIPSCO shows total projected costs of $230,550, calculated using an average cost per mile; however, NIPSCO budgets $100,000 with no explanation of how the amount was determined. He recommended removal of Adjustment OM 2I.

Mr. Dermody disagreed with NIPSCO's Adjustment OM 2J because NIPSCO failed to show that the expenses in Adjustment OM 2J are incremental to those already included in NIPSCO's base rates. NIPSCO witness Stone discussed how NIPSCO based this program cost on its historical frequency of deficiencies detected from leak surveys, including service risers, meters, or service lines in inappropriate locations that require relocation, and loops and risers that require painting, replacement, or rebuild to protect them from atmospheric corrosion. Mr. Dermody explained that not only does NIPSCO have a history of conducting leak surveys, but it appears that federal regulations already require NIPSCO to conduct such surveys and take appropriate action. He stated that if NIPSCO is in compliance with the federal regulations, and it is already conducting leak surveys, NIPSCO is already performing the work. Although Mr. Stone characterized this expense as a new AOC program, Mr. Dermody testified that at least some expenses for the activities covered under the federal regulations must already be contained in NIPSCO's current O&M expense. He stated that NIPSCO has not demonstrated any reason why these AOCs need to be treated differently than they have in the past. He noted that NIPSCO advised that the activities in this adjustment have been performed in the past, but NIPSCO did not provide the historical costs for all of the activities. Without this information, Mr. Dermody concluded that it cannot be determined whether the program expense is incremental to the expense already embedded in base rates. Further, while NIPSCO alleges that costs could be reduced over time as customers are educated about meter locations, it does not quantify any reduction to costs due to this adjustment. Mr. Dermody testified that NIPSCO has failed to support the reasonableness of this proposed O&M expense adjustment. He recommended removal of Adjustment OM 2J.

Mr. Dermody disagreed with NIPSCO's Adjustment OM 2L because painting large gas assets is not a new maintenance activity for NIPSCO and the expenses are already included in NIPSCO's base rates. He stated NIPSCO has not established that these activities are different from existing activities and provided no support to indicate new facilities or equipment have increased painting cost. NIPSCO did not support the need for an increase in these activities. He recommended removal of Adjustment OM 2L.

D. **<u>Amy E. Larsen</u>.** Ms. Larsen, Utility Analyst II, presented testimony that addressed several adjustments proposed by NIPSCO, including the linens project, critical valve program, and the amortization of proposed rate case expense.

With respect to NIPSCO's linens project, Ms. Larsen testified that the linens project had been funded up to $12.2 million through NIPSCO's Gas TDSIC Plan. Due to poor contractor performance, NIPSCO completed only 65% of the project in spite of a reduction in scope and increase in budget. NIPSCO did not show how long it will take to complete the project or how much additional funding will be required to ultimately complete the project. She explained that it was NIPSCO's obligation to responsibly manage the linens project and its contract with its vendor. Ratepayers have already provided adequate funding for the linens project; the failure to generate any meaningful outcome from the project is not the ongoing responsibility of ratepayers. Based on that conclusion, she recommended the exclusion of the linens project from NIPSCO's revenue requirement.

Ms. Larsen was also critical of NIPSCO's proposed adjustment to increase its revenue requirement for completion of its proposed critical valve program. She testified that NIPSCO failed to demonstrate that the proposed ratemaking adjustment of $500,000 was reliable.

Ms. Larsen's testimony also addressed the proposed $1,000,000 annual adjustment for improvements to LaPorte Training Center. That amount includes hiring new employees and making technology and software investments. She explained that while NIPSCO states it will deliver new and improved training to its employees, it does not support its estimate with a plan showing how it is going to accomplish this or how this new effort is improved or incremental to its current model. She noted that a training program is already in place. The need for additional staff and resources was not supported. She also suggested that NIPSCO had been inconsistent in explaining the nature and extent of its structured on-the-job training program. Ms. Larsen recommended the removal of the proposed adjustment for improvements to LaPorte Training Center.

Ms. Larsen also testified about the proposed Right-of-Way Encroachment program and the associated pro forma ratemaking adjustment of $500,000. She indicated that NIPSCO did not show adequate information to support the need for more than triple the number of annual land surveys it will complete in a year. She recommended reducing NIPSCO's proposed adjustment from $500,000 to $248,661 based upon completing 15 surveys per year on a five-year cycle rather than the 26 proposed by NIPSCO on a three-year cycle.

Ms. Larsen also testified that NIPSCO failed to justify its proposed $1,000,000 expense to improve its OQ program (platform). NIPSCO did not explain how its current program will be improved with the additional staff, software, and testing expenses it proposed. She explained that NIPSCO's written OQ program uses employee training materials made available through Mid-West Energy Association. NIPSCO has been implementing its written operator qualification program since the inception of the federal rule, which was effective in April 2001. She also expressed concern that NIPSCO could not demonstrate how much it currently spends on its written OQ program, making it impossible to know if NIPSCO's request is reasonable or incremental to current costs. She recommended removing the costs from the base rate calculation.

Ms. Larsen was critical of NIPSCO's proposed adjustment of $1,089,109 to recover fees associated with customers using credit cards to cover the costs of allowing customers to pay with a credit card without charging these customers a separate fee. She explained that customers are currently charged fees if they pay with a debit card, credit card, or an ACH payment. Customers paying in person at a third-party location with cash or check are also charged a fee, but noted that NIPSCO's own data shows these kinds of payments are relatively uncommon. Only 10.95% of NIPSCO customers pay their combined bills using a credit card. She testified that credit card fees are not necessary or essential to the provision of utility service. It is inappropriate for all ratepayers to subsidize the cost for a service used by a small number of NIPSCO customers.

Ms. Larsen evaluated NIPSCO's proposed new test station casing program and concluded that the program had not been demonstrated to be incremental to the casing inspections and installation work it already does, the costs of which already embedded in base rates. She was concerned that NIPSCO was unable to indicate how much it is currently spending on this program. Without this information, it cannot be determined whether the cost estimate NIPSCO proposes is reasonable. Ms. Larsen recommended that NIPSCO's currently pending FMCA mechanism may be a more appropriate venue for cost recovery for this project. She recommended removing the cost from the base rate calculation.

Finally, Ms. Larsen's testimony addressed NIPSCO's rate case expense and amortization. She disputed both the amount of NIPSCO's rate case expense as well as NIPSCO's proposal to amortize the amount over a four-year period. Ms. Larsen testified that two components of NIPSCO's rate case had not been sufficiently supported and recommended reduction of rate case expense by $142,806. She further testified that NIPSCO's proposed rate case expense included $420,000 in expenses associated with modification to NIPSCO's billing system required to implement new rates resulting from this proceeding. She testified that the rationale provided in support for this expense was not sufficiently complete or comparable to be representative. She recommended removing the full cost of the billing system new rate implementation from the base rate calculation, resulting in a recommended rate case expense of $737,194. Ms. Larsen also recommended the amortization of rate case expense over seven years rather than the four years proposed by NIPSCO because that amortization matches the amortization of NIPSCO's rate case expense with the estimated filing of its next rate case as required by its anticipated filing of a successor Gas TDSIC Plan. Those recommendations result in an annual amortization of $105,313 for seven years.

E. <u>Farheen Ahmed</u>. Ms. Ahmed, Utility Analyst II, recommended an update to NIPSCO's 2018 labor expense, payroll tax expense, and other benefits such as 401(k), and incentive compensation as a result of changes to labor expense. She proposed changes to pension expense and capital structure.

Ms. Ahmed agreed with NIPSCO's methodology used to calculate the Forward Test Year labor expense, but NIPSCO's proposed Forward Test Year labor expense does not reflect the most recent changes indicated by NIPSCO in discovery. Specifically, NIPSCO provided a list of all employees who switched from NIPSCO to NCSC and vice versa but had not provided the calculation of the amount already included in its OM 1 labor adjustment for those employees. Also, NIPSCO did not provide the amount that should have been included after the employees' reclassification. Therefore, she recommended NIPSCO update its schedule to reflect the most recent personnel changes and produce a corrected 2018 Forward Test Year labor expense. She recommended NIPSCO also needs to adjust payroll tax to recognize the effect of the labor adjustment and changes to other benefits such as 401(k), incentive compensation, or any other adjustments affected by the proposed labor adjustment.

Ms. Ahmed agreed with NIPSCO's methodology used to calculate the Forward Test Year pension expense, but she stated that NIPSCO's proposed Forward Test Year pension expense does not reflect the most recent changes indicated by NIPSCO in discovery. Specifically, NIPSCO confirmed making a $165,670,997 pension contribution on September 14, 2017, which was not reflected in its case-in-chief. Ms. Ahmed included the $165,670,997 pension contribution as a component of NIPSCO's overall WACC in its capital structure. NIPSCO confirmed a decrease in 2018 pension expense allocated to NIPSCO. In discovery, NIPSCO provided an updated work paper, reflecting the reduction in 2018 pension expense, to which Ms. Ahmed agreed.

Ms. Ahmed proposed an adjustment to the cost of NIPSCO's long-term debt included in the capital structure. She explained that NIPSCO provided the actual interest rates used for the new issuances of promissory notes and in discovery provided the anticipated cost range for any additional new issuances. She recalculated the cost of debt using the actual interest rates and the new cost range for any additional issuances as provided by NIPSCO. With the inclusion of the updates, the new cost of long-term debt is 4.98%.

Ms. Ahmed proposed an adjustment to customer deposits. Based on information provided in discovery, she determined that customer deposits in the amount of $17,639,619 have been held for more than 15 months and not returned. She recommended NIPSCO timely refund those customer deposits to the customers who have established their creditworthiness as required by 170 IAC 5-1-15(g)(1). If the deposits are presumed abandoned, NIPSCO should treat the deposits in accordance with Ind. Code ch. 32-34-1 *et seq.* Ms. Ahmed reduced the forecasted 2018 customer deposits by $17,639,619 to arrive at a Forward Test Year customer deposit amount of $54,366,522.

F. <u>Edward T. Rutter</u>. Mr. Rutter, Chief Technical Advisor, recommended NIPSCO's request to revise its depreciation accrual rates for gas plant in-service at December 31, 2018, the Forward Test Year, be approved. He recommended that cost recovery for NIPSCO's current Gas TDSIC Plan cease as of December 31, 2018. NIPSCO can seek recovery for the TDSIC projects that are not in-service by the end of the Forward Test Year in its new seven-year TDSIC Plan, which is expected to be filed in the first half of 2018.

Mr. Rutter reviewed and analyzed Mr. Spanos's Depreciation Study and the proposed annual depreciation accruals for each period, year ending December 31, 2016, and Forward Test Year December 31, 2018. He stated that in developing the service life and net salvage study for each depreciable asset group for the Historic Base Period and the Forward Test Year, Mr. Spanos performed the same analysis and review that was done in his depreciation study in Cause No. 43894.

Mr. Rutter testified the OUCC agrees with the use of the straight-line remaining-life method of depreciation to determine depreciation rates for NIPSCO's gas plant in-service for both the historical test year and the Forward Test Year. Mr. Rutter testified it is reasonable to use the life span technique to estimate the lives of significant facilities such as underground storage and

LNG facilities for ratemaking purposes. He stated that Mr. Spanos prepared his depreciation studies adopting the same underground storage and LNG facilities, techniques, procedures, analysis, and review as he used in Cause No. 43894.

Mr. Rutter testified the OUCC does not oppose the survivor curves used to develop NIPSCO's proposed annual depreciation accruals for the Historic Base Period and the Forward Test Year. He stated that the actual Iowa survivor curves used by Mr. Spanos in his Depreciation Study in this Cause varied from the Iowa survivor curves used in Cause No. 43894 but that varying the survivor curves does not indicate that there are errors.

Mr. Rutter testified the depreciation study approved in the 2010 Rate Case Order developed an overall annual accrual of $26,965,343, including the estimated amortization of the General Plant Reserve. The current Depreciation Study proposes an overall annual accrual of $61,608,681, including the estimated amortization of the General Plant Reserve, for a difference of $34,643,338. Based on his analysis, NIPSCO will experience a significant increase in the gas plant in-service from Cause No. 43894 (as of September 30, 2009) through the Forward Test Year of December 31, 2018. The gas plant in-service shown in the Depreciation Study filed in this Cause increased by $1,128,262,998, from $1,612,734,959 at September 30, 2009 to $2,740,997,957, estimated at December 31, 2018. This is a 70% increase. Based on this increase, Mr. Rutter determined what impact the increase in gas plant in-service would have on the annual accrual, assuming no change in the current annual accrual. He used the composite current depreciation accrual rates, which resulted in differences between the current approved rates calculated annual accrual and the actual Depreciation Study. However, the differences are due to rounding and are acceptable for calculating the annual accrual impact due to the increase in gas plant in-service. He stated the increase in gas plant in-service alone would have caused an increase in the annual accruals of $17,335,583. He stated this increase in annual accruals indicates that without any change in remaining lives for the depreciable groups, the annual depreciation accruals would have increased from $25,952,402 developed in the last depreciation study to $43,287,986 for the estimated gas plant in-service included in the current Depreciation Study. Based on his analysis of the $61,608,681 proposed annual accrual, only $16,363,426 is due to the impact of the increased annual accruals proposed for the Forward Test Year.

Based on Mr. Rutter's review of Mr. Spanos's Depreciation Study and the calculation of the $61,608,681 in annual depreciation accruals, he recommended NIPSCO's request to revise its depreciation accrual rates for gas plant in-service at December 31, 2018 be approved.

Mr. Rutter verified NIPSCO removed TDSIC projects and programs expected to be completed on or before December 31, 2018, from the Gas TDSIC Plan and included those amounts in its proposed rate base. He was concerned about the potential for double recovery of TDSIC costs between NIPSCO's TDSIC tracker and its Forward Test Year rate base. He recommended cost recovery of NIPSCO's current Gas TDSIC Plan cease at the end of the Forward Test Year, December 31, 2018. He stated that in establishing its Step Two rates, NIPSCO should be required to identify all TDSIC projects and programs by work order or project number consistent with the work order or project numbers approved in its current Gas TDSIC Plan. In reviewing the TDSIC projects NIPSCO included in its Forward Test Year rate base, this information will allow the OUCC and other interested parties to compare the actual, final costs of the TDSIC projects against the most recent approved seven-year plan estimate. He stated that for all remaining projects, whether work has commenced, but not been finalized, or work not begun, NIPSCO can seek approval of these costs in its new seven-year TDSIC Plan for approval. If costs are incurred by NIPSCO for projects transitioned to Forward Test Year rate base, they will no longer receive TDSIC treatment. All other projects transitioned to the new TDSIC will not be eligible for recovery until the new seven-year TDSIC Plan is approved along with the recovery mechanism.

G. Bradley E. Lorton. Mr. Lorton, Utility Analyst, testified regarding his opinion that 9.0% would be a reasonable return on NIPSCO's cost of equity. He indicated that the average ROE granted in 2016 was 9.5%. He stated that the Federal Reserve has tightened interest rates, but they remain below previous periods. Mr. Lorton then opined that passage of TDSIC legislation since NIPSCO's last base rate case reduced NIPSCO's risk. In the end, Mr. Lorton did not recommend any decrement to his ROE estimates as a result of the TDSIC tracker.

Mr. Lorton conducted a DCF analysis, utilizing a 2.9% dividend yield and a DCF growth rate of 5.9%, resulting in a DCF calculation of a 9.0% ROE. Regarding the CAPM calculation, he used an average beta of 0.69, consistent with his view of a relatively low-risk industry. He used a normalized risk-free rate of 3.5%. He calculated a market risk premium of 5.25%, and calculated a CAPM cost of equity of 7.12%. He stated that he found no evidence of dramatic changes in economic trends for the foreseeable future. He concluded by recommending a 9.0% cost of equity. Finally, he removed the impact of inflation to arrive at a recommended return on fair value of 6.35%.

H. Brien R. Krieger. Mr. Krieger, Utility Analyst, submitted testimony based on his review and analysis of NIPSCO's ACOSS, proposed rate design, and proposed monthly customer charge. He recommended approval of NIPSCO's ACOSS and proposed cost allocations for the derivation of rates, but he recommended that NIPSCO's proposed monthly customer charge not exceed 50% of the approved margin percentage increase.

Mr. Krieger explained that NIPSCO proposed to change the way it allocates transmission mains precipitated by transmission system expansion and upgrades along with the integration of Kokomo Gas and Northern Indiana Fuel & Light distribution systems into the NIPSCO system. As an example, NIPSCO's proposed change in the transmission allocator increases the fully allocated costs to the large transport industrial class (Rate 428) as compared to the ACOSS prepared in support of NIPSCO's last rate case (the "2010 Method"). In NIPSCO's proposed rate design, it mitigated the revenue requirement for Rate 428 to less than the fully allocated cost shown in both the 2010 method and its proposed ACOSS in this Cause. Mr. Krieger testified that natural gas utilities allocate transmission mains using varying methods to best reflect current conditions as transmission rate base and transmission main utilization change. Mr. Krieger agreed with NIPSCO's proposed change to transmission mains allocation methodology and the proposed COSS.

Mr. Krieger explained that the results of the cost of service study are the costs each individual rate class would be allocated if the rate class paid exactly 100% of the costs attributed to it for service. The costs allocated to the rate classes for designing the proposed rates were margin revenue requirements, exclusive of commodity costs. NIPSCO chose to mitigate the fully allocated ACOSS increases for some rate classes and avoid rate shock through its proposed rate design. He testified that NIPSCO's stated mitigation strategy is not to increase any rate more than 150% of the system average of 46.49%, and to structure rates in such a way that all rate classes share the burden of increased costs. He said that all of NIPSCO's rate classes, except off-peak interruptible service, experienced an increased cost to serve compared to present rates. As an example of the result of the mitigation strategy, Mr. Krieger noted that under NIPSCO's ACOSS, the Large Transport rate (Rate 428) would be increased by 121.2% to achieve fully allocated costs at a 6.74% rate of return. However, NIPSCO proposed to limit the increase to that class to 69.67%, and therefore, under-revenue collection remains with a Revenue to Cost ratio of 0.77. While interclass subsidies are not ideal, Mr. Krieger testified that mitigation of a particular class rates can be appropriate in instances where rate shock would occur. He explained that NIPSCO's rate design moves seven of eight rate classes closer to paying fully allocated costs while the C&I Off-Peak interruptible class revenue to cost ratio remains unchanged and that the General Service Large ratio indicates the class has moved from receiving excess revenues to paying excess revenues, though the margin increase is approximately 15% less than the system average.

Mr. Krieger explained that the total proposed margin, without miscellaneous revenues, decreased from $451,887,354 to $426,317,378 or a 46.49% to 38.20% change, as a result of the impact of the 2017 Tax Act. The revised ACOSS based on those values vary by an insignificant amount for all rate classes except the C&I Off-Peak Interruptible rate. He testified that NIPSCO did not modify its proposed rate design as a result of the revised ACOSS, thereby further increasing the percentage of margin recovered through the proposed $19.50 residential customer charge.

Mr. Krieger testified that the OUCC disagrees with NIPSCO's proposed fixed monthly residential customer charge as being inconsistent with other gas utilities in the state. Higher customer charges have a greater impact on lower consumption customers because the customer charge represents a high percentage of the total monthly bill. He noted that the minimum monthly charge also includes the TDSIC and Gas DSM charges in addition to the monthly customer charge. If approved, NIPSCO's proposed monthly residential customer charge would be greater than 57% of the total annual bill for the lowest three tiers of consumption. Mr. Krieger also analyzed the proposed monthly residential customer charge in comparison to both regional and national data obtained from the American Gas Association. Mr. Krieger recommended that the monthly residential customer charge be limited to $13.75, which represents approximately a 25% increase over the current $11.00 charge, and this charge would more closely align with recent Commission-approved residential customer charges for natural gas utilities.

10. <u>CAC's Case-in-Chief</u>.

A. <u>Kerwin L. Olson</u>. Mr. Olson, Executive Director of CAC, addressed issues related to the affordability and equity of NIPSCO's proposed gas rates and rate design. He asserted that utility cost recovery from the fixed customer charge portion of gas bills disproportionately harms the low-volume consumers within a rate class. He stated that providing for utility cost recovery through rate modifications that increase the fixed customer charge, rather than recovering the same through the volumetric charge, penalizes the low-volume consumers within a customer class. An increase to the fixed customer charge disproportionately increases the total monthly bill of low-volume consumers by a higher percentage than that of higher volume consumers.

Mr. Olson testified this dynamic raises profound equity concerns in that it will cause disproportionate harm to low-income households, and other vulnerable populations who live on a fixed-income, like the disabled and the elderly. In addition, by shifting cost recovery from volumetric charges to fixed customer charges, NIPSCO's proposal would diminish the customer price incentive to participate in energy efficiency programs or otherwise make home energy efficiency improvements. Increasing the fixed customer charge would diminish the ability of consumers to control their gas service bills. Therefore, the proposal to increase the fixed charge by any amount should be rejected. If any additional cost recovery to NIPSCO is allowed by the Commission, it should be recovered through the volumetric charge, not the fixed customer charge.

Mr. Olson testified the Commission should consider a case before the Illinois Commerce Commission and the National Association of Statute Utility Consumer Advocates' Resolution 2015-1 in determining whether NIPSCO's residential customer should be penalized with a higher fixed customer charge.

Mr. Olson testified CAC has become greatly concerned with the path Indiana has taken in recent years regarding ratemaking, especially with respect to charges and rates levied on residential customers. Residential customers have been subjected to a proliferation of trackers from our State legislature, such as TDSIC trackers, trackers for federal mandates, and trackers for DSM investments, which for electric customers now include extraordinary amounts of so-called lost revenues. He stated the harm to residential customers has been exacerbated by Indiana's recent trend toward allowing utilities to increase the fixed customer charge portion of residential customers' bills. The Commission and the public have also been burdened with this piecemeal approach to utility regulation from the State legislature, lacking clear and concise energy policy. It has led to an unmanageable caseload and an uneven playing field. He opined that what Indiana needs is commonsense, transparent policy, and guidance to establish an equitable rate structure which maintains the financial health of the utilities while ensuring just and reasonable rates for consumers and service offerings that are in the public interest. CAC recommends that the Commission begin a robust discussion regarding policy options and rate design to find an alternative to perpetually increasing the fixed customer charge and adding more trackers. Such alternatives could include decoupling mechanisms, restructuring of utility regulation, or other solutions, all of which must include robust energy efficiency investments and protections for low income customers in order to be successful.

Mr. Olsen recommends that the Commission reject any NIPSCO proposal that would increase the fixed customer charge. Should the Commission decide to allow such a substantial increase in the monthly fixed customer charge, the Commission should consider that the fixed charge component for residential customers include a minimum level of defined service, or a certain level of gas consumption. Finally, the Commission should initiate a discussion or investigation regarding policy options and rate design to find an alternative to increasing the fixed customer charge and the addition of more trackers.

11. Industrial Group's Case-in-Chief.

A. Michael P. Gorman. Mr. Gorman, Managing Principal with Brubaker & Associates, presented testimony addressing various adjustments to NIPSCO's proposed revenue requirement, the overall rate of return, including ROE, embedded debt cost, and NIPSCO's proposal to use its fair value NOI for purposes of the earnings test. Mr. Gorman noted the approximate $25.6 million reduction in NIPSCO's requested revenue requirement to reflect the change in federal corporate income tax rate related to passage of the 2017 Tax Act. He also noted that the protected amount of excess ADIT is being amortized using the ARAM method, while non-normalized excess ADIT can be returned over any period approved by the Commission. He proposed a five-year amortization period for the unprotected excess ADIT.

Mr. Gorman recommended a return on common equity between 8.60% and 9.30%. He also proposed using an average year rate base during the projected test year rather than NIPSCO's rate base at the end of its Future Test Year. Correspondingly, he proposed an average capital structure rather than use of the end-of-year capital structure. Mr. Gorman addressed inclusion of the PPA in NIPSCO's capital structure.

Mr. Gorman addressed the head count at NIPSCO and proposed reducing NIPSCO's revenue requirement to reflect the (lower) number of employees as of January 2018. Mr. Gorman reviewed the increase in corporate service costs and concluded that while NIPSCO had explained the increase in costs from 2016 to 2018, it had not adequately addressed the increase from 2012 through 2015, and therefore, he recommended a reduction in NCSC costs by $9.5 million. He also proposed the appropriate amortization period for TDSIC deferred cost was ten years, further reducing NIPSCO's revenue requirement by $3.9 million.

B. **<u>Nicholas Phillips, Jr</u>.** Mr. Phillips, Jr., Principal with Brubaker & Associates, presented testimony concerning the appropriate cost allocation methodology and the proper design of NIPSCO's gas rates. He explained that there are certain general principles that should form the basis for cost allocation and rate design. Mr. Phillips took issue with NIPSCO's use of the Peak and Average ("P&A") method to allocate demand related transmission costs. He recommended that a Peak Day demand allocation be used in place of the proposed P&A method. He stated that the P&A method is in direct conflict with the coincident peak method proposed by NIPSCO in its last base rate case. He noted that NIPSCO's Transportation Rates 428 and 438 served NIPSCO and its customers well, including during the polar vortex. He noted that the Industrial Group includes large employers who manufacture goods that must compete on a worldwide basis. He asserted that transportation customers should enjoy rate structures that maintain a favorable business climate. He concluded by recommending that the form of NIPSCO's current Rates 428 and 438 be maintained and that customers served on those rates receive no more than the average overall percentage increase approved in this case.

12. **<u>SDI's Case-in-Chief</u>.**

A. **<u>Kevin C. Higgins</u>.** Mr. Higgins, Principal with Energy Strategies, LLC, addressed issues associated with Mr. Amen's cost of service study related to the assignment of costs within NIPSCO Rate 428 – Large Transportation, including his recommendation that cost assignment be based on the pressure associated with facilities from which transportation service is delivered.

Mr. Higgins testified that NIPSCO's cost of service study properly recognized that a significant proportion of the gas delivered to transportation customers is delivered directly from systems of greater that 200 PSIG by Rate 428. He contended that NIPSCO should have better reflected that distinction by allocating costs associated with lower pressure systems solely to those customers rather than across the rate class as a whole. Mr. Higgins explained that by differentiating between customers taking service from high pressure systems within Rate 428, cost responsibility for ratemaking purposes would be aligned with cost causation by reflecting a reduced allocation of low pressure facility costs to customers not making use of the underlying assets.

Mr. Higgins sponsored an analysis that supported a proposed rate design based upon a revised allocation of both demand and volumetric rate determinants between the Rate 428 customers receiving service from high pressure facilities and those receiving service from lower pressure facilities. He proposed to retain NIPSCO's proposal to recover 25% of demand related costs through a demand charge, then to make equal adjustments to the first and second volumetric blocks. The result of Mr. Higgins's analysis was an increase to both blocks of the volumetric rate to customers receiving service from low pressure facilities, and a decrease to both blocks for those served from high pressure facilities. He explained that his proposal would not impact any other class of customer by only reallocating costs within Rate 428. He indicated that a similar situation existed with respect to NIPSCO's General Transportation and Balancing Service under Rate 438.

Mr. Higgins was also critical of NIPSCO's proposal to use the P&A method for the allocation of transmission plant within its cost of service study, contending that it unreasonably shifts costs to high load factor customer classes by allocating 44% of transmission plant based on average demand rather than peak demand. Mr. Higgins recommended that the Commission adopt the alternative cost of service study that allocated transmission on the basis of Design Day peak as had been done in NIPSCO's last general rate case. He testified that adoption of that methodology would not reduce revenue allocated to Rate 428 because NIPSCO's proposed mitigation methodology would constrain cost allocation to the Class regardless of which allocation methodology is adopted. He concluded that use of the P&A methodology unreasonably distorts class cost allocation and should be rejected.

13. <u>Cross-Answering Evidence</u>.

A. <u>Industrial Group</u>. Mr. Phillips responded to the testimony of OUCC Witness Krieger, and he disagreed with Mr. Krieger's conclusion that NIPSCO should change the way it allocates transmission mains. Mr. Phillips stated that the P&A method used by NIPSCO was illogical and had no link to cost causation. Mr. Phillips noted that FERC uses a SFV method of allocating costs since Order 636 in 1992. He concluded that the P&A method of allocation should be rejected by the Commission.

14. <u>NIPSCO's Rebuttal Evidence</u>.

A. <u>Mr. Shambo</u>. Mr. Shambo's rebuttal testimony addressed the OUCC's recommendation to move three O&M adjustments into NIPSCO's pending Gas FMCA Proceeding. He testified that NIPSCO is willing to support the proposal as described by OUCC witnesses Dermody and Larsen, subject to two conditions. First, inclusion of those projects in the Gas FMCA Proceeding must be accompanied by the stipulation that the projects are "federally mandated requirements" within the meaning of Ind. Code § 8-1-8.4-5. Second, NIPSCO is willing to include those three projects as components of its Pipeline Plan if the estimated costs for those projects as described by NIPSCO witnesses Stone and Roberts are deemed to be acceptable for approval by the Commission. He noted that while all three are clearly associated with ongoing compliance with a federal mandate, they are also appropriate for inclusion in the revenue requirement to be approved in this case in the event that such conditions are unacceptable to the OUCC or other Parties.

Mr. Shambo also addressed the OUCC's position on the use of the approved fair value NOI for purposes of the GCA earnings test. He explained that NIPSCO maintains that a fair value NOI is an appropriate valuation of its earnings for inclusion in the calculation of its "earnings bank" because Indiana law provides for fair value ratemaking and such ratemaking is appropriate for all purposes contemplated by the Indiana General Assembly.

In response to the OUCC's recommendation to deny recovery of credit card fees, Mr. Shambo testified that NIPSCO continues to receive negative comments from customers through J.D. Power and other customer satisfaction surveys regarding the fee currently charged when making a payment using a debit card, credit card, or an ACH payment. He said customers expect to be able to use these forms of payment without incurring an additional charge, just as they do at a grocery store, pharmacy, hotel, or numerous other places where these forms of payment are accepted. Mr. Shambo noted that several of NIPSCO's affiliated companies have eliminated these fees paid by customers, and debit/credit card payments have steadily climbed. He testified that NIPSCO anticipates that the number of customers paying via these methods would grow to over 40% within the first five years if no fee was incurred for use of these types of payment.

Mr. Shambo indicated that the OUCC's position on customer deposits was not appropriate and should be rejected. Mr. Shambo explained that NIPSCO's treatment of the customer deposit balance is reasonable, appropriate, and consistent with the Commission's Standards of Service for Gas Utilities. He noted that OUCC witness Ahmed appears to have concluded that all deposits held for more than 15 months should be considered "unclaimed" under the Commission's Rules without addressing whether deposits are appropriately held under the Commission's creditworthiness standards. He testified that NIPSCO has confirmed that the gas deposits identified for refund by Ms. Ahmed are associated with current NIPSCO customers, including those dating back to 1946, and those customers have not met the deposit refund criteria. He explained that NIPSCO's internal business rules apply the more generous electric deposit refund criteria from the Commission's electric standards of service to deposits for residential combination customers, thus providing for the establishment of creditworthiness based on timely payment for a shorter period. He also explained that once creditworthiness criteria are met, the deposit and any accrued interest are automatically applied against the current account balance and reflected on the customer's next bill.

Mr. Shambo also rebutted the Industrial Group's position on NIPSCO's proposed revisions to its transportation tariffs, including curtailment and minimum Plant Protection Levels. Mr. Shambo testified that NIPSCO is unique among Indiana LDCs in the size of its industrial throughput both in real terms and relative to its overall load. While NIPSCO has been fortunate to avoid the need for curtailment and applauds the informal cooperation of its largest industrial customers, it would be unconscionable for any utility not to plan for such events. He observed that NIPSCO has gone through a number of tariff iterations calling for customer established or mutually agreeable plant protection levels or similar mechanisms, resulting in the insistence by some customers that a reasonable plant protection level for curtailment is more than 100% of their highest daily usage. The upshot of such a "reasonable" plant protection level is the practical inability to curtail the customer even in times of system emergency without violating NIPSCO's tariff. Mr. Shambo testified that NIPSCO needs to have workable tools to protect its system and other customers; NIPSCO is committed to a fair but consistently calculated plant protection level.

Mr. Shambo also disagreed with Industrial Group witness Phillips that a demand charge is not needed for transportation customers. He testified that a demand charge recovers a portion of the costs allocated to a rate class that would otherwise be collected through a variable or other charge. It is not an additional increment. The total revenue requirement will not change based upon the existence of a demand charge. He explained that a demand charge serves to encourage customers toward the efficient use of capacity on the system and rewards those customers able to manage their usage to a high load factor.

In his rebuttal testimony, Mr. Shambo addressed the Parties' positions on the magnitude of NIPSCO's proposed fixed monthly charge for residential customers. He disagreed with OUCC witness Krieger that the focus of the Commission should be on whether NIPSCO's proposal is "in line" with the customer charge of other gas utilities and explained that the premise of SFV rate design is that costs incurred by utilities should be recovered in a manner consistent with cost causation. He noted that the Commission has agreed with that premise and has previously promoted the movement toward SFV rate design in its Orders. He testified that NIPSCO understands the concept of gradualism, but that Mr. Krieger's conclusion that the focus be on the range of fixed charges for other utilities is not consistent with the Commission's approach or with sound ratemaking practice. He noted that the Commission had concluded that "SFV rate designs are attractive because they align basic cost causation principals of ratemaking" in its 2009 natural gas rate design investigation.[20] But Mr. Krieger's analysis was based primarily on a comparison between the rate structures of unrelated utilities rather than cost causation. He concluded that Mr. Krieger's reliance on principles of gradualism belies a recognition of the economic merits of SFV ratemaking. He reiterated NIPSCO's position that the $19.50 proposed customer charge for residential customers represents a reasonable degree of movement toward SFV rates that, in the absence of gradualism, would produce a fixed monthly charge of $29.74. Mr. Shambo noted NIPSCO's recognition that gradualism is an issue about which reasonable parties may differ based on the facts and circumstances presented in each case, but that it is NIPSCO's view that movement toward alignment between cost causation and customer rates is critical.

B. **Ms. Konold.** Ms. Konold filed rebuttal testimony to do the following: (i) address Industrial Group's contention that rate base should be calculated based upon monthly average balances during the test period rather than an end of test period calculation; (ii) address various revenue requirements issues and pro forma adjustments raised by the OUCC and the Industrial Group; (iii) discuss certain amortization period issues raised by the OUCC and the Industrial Group; (iv) explain NIPSCO's proposal for returning deferred federal tax expense savings accruing as a result of the reduction in the federal corporate tax rate; (v) provide actual utility plant in-service, associated depreciation, and capital structure at December 31 2017; (vi) provide updated projections for utility plant in-service, associated depreciation, and capital structure at May 31, 2018, and December 31, 2018; and (vii) present revised schedules supporting

[20] *Re Investigation into Rate Design Alternatives and Energy Efficiency Measures for Natural Gas Utilities,* Cause No. 43180, 2009 WL 3455940 (IURC Oct. 21, 2009).

NIPSCO's revenue requirements and reflecting NIPSCO's rebuttal positions for both Step One and Step Two.

Ms. Konold sponsored Pet. Ex. 3-R, Attach. 3-A-R1 through 3-F-R1, representing the schedules supporting the calculation of NIPSCO's revenue requirement based on the 12-month period ending May 31, 2018. NIPSCO provided updated schedules for all figures that have been updated since its supplemental direct filing.

Ms. Konold disagreed with Mr. Gorman's suggestion that rate base should be calculated using 13-month balances rather than the end of test period calculation (as of December 31, 2018) used by NIPSCO. She explained that Indiana regulatory custom is to use an end of test period calculation of rate base as is illustrated by the Commission's MSFRs. See 170 IAC 1-5-5(3) and (4). She testified that the same concept is applicable for both historic test period cases and for recent future test period cases. She also testified that a 13-month average balance rate base calculation would be technically problematic because it is not a good fit with Indiana's used and useful requirement in a Future Test Year context. It also would not fit with Indiana's TDSIC Statute, which allows full recovery of approved TDSIC projects (80% in a TDSIC tracker and 20% deferred for subsequent recovery in a base rate case) resulting in less than full recovery of NIPSCO's pre-approved TDSIC projects. She noted that NIPSCO's proposed certification procedures will be more representative of utility plant in-service that will be used and useful in providing service to customers if based on year-end results.

Ms. Konold agreed with Mr. Gorman that rate base calculation methodology should be synched up with depreciation methodology and testified NIPSCO's end of test period rate base calculation methodology does just that. She also described an additional adjustment to the Forward Test Year operating revenues to reflect the impact of the reduced federal income tax rate resulting from the 2017 Tax Act. She testified that NIPSCO annualized the 2018 revenues to reflect the impact of the reduced federal income tax rate of 21% in an adjustment sponsored by NIPSCO witness Westerhausen.

Ms. Konold's testimony also addressed the OUCC's proposal to reduce NIPSCO's rate case expenses in several areas. Ms. Larsen testified that two components of NIPSCO's rate case had not been sufficiently supported and recommended reduction of rate case expense by $142,806. Ms. Konold said that NIPSCO confirmed that the services performed by ScottMadden for $45,000 were related to the filing of NIPSCO's first forward looking rate case. She disagreed with OUCC Witness Larsen that the ScottMadden expenses should be denied. She also disagreed with Ms. Larsen that the expenses associated with the Adecco temporary employees have not been sufficiently supported because NIPSCO explained in discovery that its use of Adecco temporary employees was to reconcile GAAP and FERC actuals to identify adjustments required to convert a GAAP budget into a FERC ratemaking budget as well as to support the MSFR process. Ms. Konold testified that no rule, requirement, or precedent she was aware of supports Ms. Larsen's proposition that rate case expenses should be excluded because invoices did not specifically identify the case associated with the engagement. She noted that the MSFRs require identification of the services and the estimated costs of the services, but not the specific companies or vendors and that rate case expense vendors cannot always be fully identified at the front end of a case. Finally, Ms. Konold disagreed with Ms. Larsen's view that billing system costs associated with revised rate implementation should not be recoverable. She explained that NIPSCO provided an estimate based on the actual costs of the most recent similar project, NIPSCO's electric rate case, and those costs should be largely analogous.

Ms. Konold agreed with the OUCC's proposal that certain expenses associated with the Northwest Indiana Forum and a misallocation of expenses to NIPSCO division be excluded from revenue requirements, along with certain charitable contributions and advertising expenses. Ms. Konold updated the revenue requirement to reflect the OUCC's proposed adjustments.

Ms. Konold disagreed with the OUCC's proposal that NIPSCO should update labor expense, payroll tax expense, other benefits, and pension expense relating to employee moves between NCSC and NIPSCO in 2017. She stated that the employee moves between NCSC and NIPSCO during 2017 were primarily a function of a restructuring of the way that regulatory services are provided to the NiSource affiliates. NIPSCO is not proposing a change to the 2018 projected operating expenses. She described the restructuring and the resulting changes in NIPSCO's organization structure. She testified the reorganization did not result in any changes in operating expenses that are not reflected in the projected expenses for the 2018 Future Test Year in this proceeding.

She also disagreed with the OUCC's proposal that rate case expenses should be amortized over seven years, instead of four years as proposed by NIPSCO. She stated that although the TDSIC statute sets the upper limit of how long a utility with an approved TDSIC plan may go without filing a base rate case, it does not preclude the filing of more frequent base rate cases. She testified that four years is a more typical interval between rate cases. Ms. Konold also disagreed with the OUCC's and Industrial Group's proposals for amortization of NIPSCO's deferred TDSIC expenses over of a seven-year and ten-year period, respectively. She explained that it is appropriate to amortize those deferred expenses over a similar period to that in which they were incurred. She reiterated NIPSCO's position that four years is an appropriate and reasonable amortization period.

Ms. Konold agreed with the OUCC's recommendation that NIPSCO's pension expense be reduced to reflect the growth of NIPSCO's PPA.

Ms. Konold described NIPSCO's proposal for returning deferred federal income tax savings to its customers in her rebuttal testimony. She stated that upon implementation of revised base rates incorporating the reduction in the federal income tax rate, NIPSCO will be able to determine the final regulatory liability or refund related to the tax savings accruing from the reduction in federal income taxes. She explained that NIPSCO proposes to include this refund in the first TDSIC tracker filing after the final balance is known, permitting the pass back in a timely manner and continuing to true-up any variances resulting from over or under recoveries.

Ms. Konold sponsored the following on behalf of NIPSCO: (i) actual utility plant in-service, associated depreciation, and capital structure at December 31, 2017 (Pet. Ex. 3-R, Attach. 3-E-R and 3-F-R); (ii) utility plant in-service, associated depreciation, and capital structure at May 31, 2018 (Pet. Ex. 3-R, Attach. 3-E-R1 and 3-F-R1); and (iii) utility plant in-service, associated depreciation, and capital structure at December 31, 2018 (Pet. Ex. 3-R, Attach. 3-E-R and 3-F-R). Ms. Konold testified that consistent with the OUCC's recommendation, the capital structures presented as part of NIPSCO's rebuttal reflect the impact of the $165.3 million pension contribution made on September 14, 2017. The capital structures presented also reflect the impact of the long-term debt issued associated with this payment.

Ms. Konold testified that Industrial Group witness Gorman's contention that NIPSCO has not demonstrated that the PPA was funded by investor capital rather than collections of pension-related costs from retail customers was fundamentally incorrect. She explained that the PPA represents the difference between the cumulative amounts of pension contributions to NIPSCO's pension trust fund less the cumulative amount of pension expense recorded by NIPSCO.

Ms. Konold testified that NIPSCO's books and records and the balance sheet serve as a cumulative life-to-date record of activity. Those documents are audited on an annual basis and reviewed on a quarterly basis by external auditors who provide an opinion as to the accuracy of the financial statements. As a result, she disagreed with Industrial Group witness Gorman's contention that NIPSCO does not know how much of its contributions in excess of its recorded pension expense have been collected from ratepayers because it does not know the level of expense included in rates since it began tracking the PPA. She testified that NiSource and NIPSCO have numerous other preventative and detective internal controls that provide a framework for accurate financial reporting and that it is reasonable to use the PPA included in NIPSCO's books and records as an accurate representation of NIPSCO's contributions in excess of its recorded pension expense.

C. Mr. Scott. Mr. Scott provided an update on 2017 actual O&M expenses experienced by NIPSCO, and he addressed the OUCC's proposed adjustments to operating revenues, as well as issues raised by Industrial Group witness Gorman about NIPSCO's head count. He explained how actual 2017 expenses compared to the projected 2017 and 2018 expenses. He testified that the results demonstrate that NIPSCO's actual 2017 expenses exceeded the 2017 expense budget by 5.9% and were higher than the 2018 projected expense presented in this case.

Mr. Scott disagreed with the OUCC's proposed operating revenue adjustment relating to interruptible sales revenues, stating that because interruptible sales revenue is relatively small, NIPSCO does not budget for it on a standalone basis. It is included in NIPSCO's budget for transportation volumes. He explained that NIPSCO records actual interruptible sales revenues received that are then recorded on a standalone basis. He clarified that while the transportation revenue budget does not include interruptible sales revenue as the OUCC correctly contends, the "Retail Sales" budget subcomponent does include interruptible sales revenue. If the OUCC's proposed adjustment were made, it would lead to duplicative revenue forecasts in the Forward Test Year.

Mr. Scott also disagreed with the OUCC's proposed operating revenue adjustments relating to miscellaneous service revenues, explaining that NIPSCO's use of the most recent historical value as a basis for the forecast is also a reasonable approach. This is an appropriate methodology for this account balance, based on the nature and materiality of this account.

Mr. Scott testified that the employee head count reports are prepared on a NIPSCO total company basis. The head count report referenced by Mr. Gorman includes all NIPSCO employees, not just those dedicated to the NIPSCO utility. He explained that when a manual breakdown of employees is performed, NIPSCO actually has 33 more employees than the level NIPSCO included in the cost of service in this case, not 75 less as referenced in Mr. Gorman's testimony. Therefore, no reduction to labor and benefits should be made. He added that when NIPSCO has temporary vacancies throughout the year, the base wage savings are generally offset by increased overtime costs and higher utilization of contractors.

D. **Mr. Stone.** Mr. Stone addressed the OUCC's proposals concerning right-of-way clearing, AOCs, atmospheric corrosion, linen mining, LaPorte Training Center and curriculum, legacy cross-bores, and casing test station program. Mr. Stone agreed with the OUCC's proposal to move NIPSCO's proposed legacy cross-bore identification program (Adjustment OM 2F) and new test station casing program (Adjustment OM 2R) into NIPSCO's pending Gas FMCA Proceeding, subject to the clarifications identified by Mr. Shambo. Pet. Ex. 3, Attach. 3-C and 3-D, Adjust. OM 2F. Pet. Ex. 3, Attach. 3-D, Adjust. OM 2R. While he agreed that those programs are appropriately included in the Gas FMCA Proceeding, he presented testimony rebutting the assertion that the cost estimates for those programs had not been sufficiently developed.

Mr. Stone disagreed that a 40-year cycle is appropriate for the clearing of rights-of-way, and he testified that the longer the period between clearing cycles, the more time that vegetation has to grow and mature. Pet. Ex. 3, Adjust. OM 2B. He testified that a 15-year cycle optimizes the effectiveness and efficiency of clearing operations and is appropriate for the maintenance of rights-of-way. A 15-year cycle would reduce the likelihood of damages to lines in the right-of-way. Mr. Stone testified the estimate was developed based on NIPSCO's previous right-of-way clearing and cutting experience.

Mr. Stone disagreed with the OUCC's proposal to eliminate NIPSCO's proposed AOC program. Pet. Ex. 3, Attach. 3-D, OM 2J. He explained that OUCC witness Dermody incorrectly characterized compliance with federal leak survey standards as being the same as performing the work to remediate AOCs, noting that Adjustment OM 2J proposes incremental funding for the remediation of AOCs, not the performance of required inspections. He stated that the cost estimate was developed to identify the cost of remediation of AOCs to remedy a hazardous situation that generally occurs at or near the customer meter set. If not addressed, the situation could possibly result in failure and interruption or a dangerous leak.

Mr. Stone also disagreed with the OUCC's proposal to eliminate NIPSCO's atmospheric corrosion program. Pet. Ex. 3, Attach. 3-D, Adjust. OM 2L. Mr. Stone stated that the adjustment is limited to specific large above ground assets associated with NIPSCO's storage facilities and PODs. He testified that the activities contemplated are incremental to the other painting activities referenced by Mr. Dermody.

Mr. Stone disagreed with Ms. Larsen's statement that the linen mining project has already been paid for by NIPSCO's customers. Mr. Stone said that the entire cost will not be recovered from customers through the TDSIC tracker prior to implementing rates in this proceeding. The costs of the program will continue. He stated Adjustment OM 2N is intended to normalize NIPSCO's expenses for maintaining internal labor and space to accommodate the incorporation of data into NIPSCO's GIS and also the ongoing run rate of external labor for the mining of digital data. Pet. Ex. 3, Attach. 3-D, Adjust. OM 2N. Mr. Stone disagreed with Ms. Larsen's proposal to eliminate the entirety of Adjustment OM 2N.

Mr. Stone disagreed with Ms. Larsen's proposal to eliminate all of Adjustment OM 2P for LaPorte Training Center improvements, explaining that NiSource has recently updated its gas standards to incorporate both changes in industry practices and pipeline safety requirements. Pet. Ex. 3, Attach. 3-D, Adjust. OM 2P. Mr. Stone said that it is increasingly critical that NIPSCO's front line employees, supervisors, and contractors be provided with the most thorough and complete training possible to ensure the safe and compliant operation of NIPSCO's gas facilities. He noted that while LaPorte Training Center is an excellent physical facility, it lacks current technological resources including software to support its mission. He testified the estimate for Adjustment OM 2P was based on the annual run rate for the LaPorte Training Center inclusive of the addition of new resources to enhance and apply new training tools.

E. **Mr. Roberts.** Mr. Roberts addressed issues raised by OUCC witnesses Dermody and Larsen. He disagreed with their proposals to move NIPSCO's proposed transmission risk program into NIPSCO's pending Gas FMCA proceeding. He also disagreed with the OUCC's positions regarding Adjustments OM 2H, OM 2I, OM 2O, OM 2Q, and OM 2S.

Mr. Roberts opposed moving funding for the transmission risk model to the Gas FMCA Proceeding. Pet. Ex. 3, Attach. 3-D, Adjust. OM 2D. He explained that while this project could qualify as a project for inclusion in the Gas FMCA Proceeding, the software licensure for this risk model is an ongoing operating expense that is more appropriately included in base rates. He also disagreed with the proposal to reduce the adjustment by the 30% contingency. He stated that if the Commission approves incorporating the project into the Gas FMCA Proceeding, NIPSCO customers will ultimately only pay for the actual cost of the project, so the contingency remains appropriate to include as a reasonable estimate of costs.

Mr. Roberts disagreed with Mr. Dermody's proposal to eliminate all of the MAOP – Distribution project. Pet. Ex. 3, Attach. 3-D, Adjust. OM 2H. He reiterated that the estimate for the program is reasonable and reliable because NIPSCO used actual experience from a previous project and actual estimates from third-party vendors. He also noted that NIPSCO's failure to spend the 2017 estimate was solely related to the availability of external resources.

Mr. Roberts also disagreed with Mr. Dermody's proposal to eliminate all costs associated MAOP - Transmission project. Pet. Ex. 3, Attach. 3-D, Adjust. OM 2I. He stated that using a prorated cost for NIPSCO's miles of transmission pipeline in comparison to other LDCs mileage is a valid way of estimating these costs for NIPSCO. Mr. Roberts testified NIPSCO's TIMP approach to the Transmission MAOP project is reasonable and reliable. To prepare estimates, NIPSCO used experienced contractor, affiliate costs, and vendor quotes.

Mr. Roberts was critical of OUCC witness Larsen's proposal to eliminate NIPSCO's proposed emergency valve program and explained that uncertainty surrounding the number of critical valves that require remediation drives the need for the program. Pet. Ex. 3, Attach. 3-D, Adjust. OM 2O. He pointed out that if NIPSCO knew precisely where all of these valves were located and what steps were required to bring them up to current standards, there would be no need to develop the program at all. The work to be performed is field work. He testified that the estimate was developed based on the experience gained in developing programs in other states.

Mr. Roberts testified that Ms. Larsen's proposal to reduce the right-of-way encroachment program was inappropriate. Pet. Ex. 3, Attach. 3-D, Adjust. OM 2Q. Mr. Roberts noted that Ms. Larsen's proposed reduction was based on the historic average number of annual right-of-way surveys adjusted solely to the change in NIPSCO's leak survey cycle from a five-year cycle to a three-year cycle on distribution systems. He said that while her proposed run rate of 15 inspections per year is an improvement over NIPSCO's historic run rate, it is not consistent with NIPSCO's expectation to reduce the number of encroachments. He testified the estimate is based on actual vendor rates for services anticipated. The estimate factors in all of the elements driving increased use of those services, not just the accelerated leak survey cycle.

Mr. Roberts also testified that aligning qualification testing and assessment with actual NIPSCO specific standards and operating procedures versus general industry knowledge strengthens the requirements of qualification and therefore disagreed with Ms. Larsen's proposal to eliminate NIPSCO's proposed enhancements to its OQ platform. Pet. Ex. 3, Attach. 3-D, Adjust. OM 2S-18R. He stated that the enhancement of the OQ platform will allow NIPSCO to begin administering written knowledge testing on all re-qualifications, assuring critical knowledge related to covered tasks has been retained. Mr. Roberts testified that the positions requested are incremental positions that will create, maintain, administer, manage, and oversee NIPSCO's OQ platform. The estimates were based on market pricing of job descriptions and vendor pricing quotes for outside services related to proctoring and testing facilities. The estimates were also based on NIPSCO's experience deploying similar improvements in affiliate LDCs in Pennsylvania and Virginia.

F. <u>Mr. Campbell</u>. Mr. Campbell responded to Industrial Group witness Phillips's recommendation that Rates 428 and 438 be maintained as is and NIPSCO's proposed revisions to those rates be rejected. He also responded to Mr. Phillips's recommendation that proposed Rider 189 clearly state that current customers are wholly exempt and will never be required to take service under Rider 189 even if their operations and usage patterns were to change drastically. He also responded to Mr. Phillips's criticisms of NIPSCO's proposal to clarify and simplify the curtailment procedures set forth in Rule 13 of NIPSCO's Rules and Regulations.

Mr. Campbell testified that under NIPSCO's proposed revised Rule 13, firm services will be prioritized and curtailed in the following order: (i) transportation service under Rates 128 and 138 above the annual Curtailment Threshold calculated as the 50th Percentile of Daily Usage; (ii) transportation service under Rates 128 and 138 between the annual Curtailment Threshold calculated as the 20th Percentile of Daily Usage; and (iii) service under all other firm Rates upon declaration of a curtailment. Mr. Campbell testified that the process will better protect the integrity of the system. The current process is unwieldy and difficult to implement. It is virtually unusable in the event of a system emergency. He explained that customer usages were reviewed and a determination made that the 50th percentile is the median gas usage by customers. It represents a level of usage NIPSCO typically observes during normal operations. Accordingly, actions required by customers to curtail usage to this level should be limited.

Mr. Campbell testified that NIPSCO currently serves over 200 customers under Rates 428 and 438. Adopting differing approaches for multiple customers would be unwieldy. Mr. Campbell testified that from a customer perspective, inclusion of specific curtailment percentiles in the tariff provides a demand level around which customers can plan so that will know what might be expected in the unlikely event of curtailment. Customers can determine ahead of time what types of equipment or processes might need to be adjusted.

Mr. Campbell recommended the Commission approve NIPSCO's revisions to Rates 128 and 138 as proposed, as well as proposed Rider 189, and changes to Rule 13. The proposed changes simplify sections that have duplicative language, clarify circumstances under which NIPSCO can implement curtailment to the benefit of NIPSCO and its customers, and refresh language based on recent operational experience.

G. Mr. McCuen. Mr. McCuen described several 2017 Tax Act updates to the WACC that were not incorporated into his supplemental direct testimony. He stated that there is no impact to the December 31, 2017 WACC because the reduction in NIPSCO's deferred tax accounts (190, 282, and 283) are equally offset by regulatory assets and liabilities (182 and 254) for the remeasurement of NIPSCO's accumulated deferred taxes. He explained that the amount of pass back of excess deferred taxes in 2018 would also reduce the overall Deferred Income Taxes included in the WACC. But Deferred Income Taxes was not updated for the supplemental filing nor was the impact of the elimination of bonus depreciation for utilities starting January 1, 2018. He testified that based on using NIPSCO's proposed amortization periods, there was a reduction of $11 million in the Deferred Income Tax, and that the elimination of the bonus depreciation deduction for 2018 puts NIPSCO into a taxable income position. He explained that NIPSCO will not create a deferred tax liability for the bonus accelerated depreciation and will start to utilize its net operating loss deferred tax asset. He testified that the net impact of these changes reduces the Deferred Income Tax included in the WACC as cost free capital by $102 million.

Mr. McCuen disagreed with OUCC witness Grosskopf's assertion that property taxes will not change with the Step Two rates. He explained that property tax expense is based on a 2017 tax return, but taxes are not due until 2018. This provides a current and relatively accurate pro forma expense amount. NIPSCO adjusted its property tax expense in its January 26, 2018 supplemental filing, which addressed changes to NIPSCO's case-in-chief as a result of the 2017 Tax Act. NIPSCO's update for the 2017 Tax Act was based on a forecast that will be updated with 2017 actuals for the Step Two filing.

Mr. McCuen also clarified how NIPSCO has treated the protected excess deferred taxes, explaining that the period identified in his supplemental testimony was a placeholder and a reasonable method to establish an estimate. He testified that NIPSCO is required to use ARAM for the protected excess deferred taxes which requires asset level detail by vintage to calculate the correct amount of amortization for the Forward Test Year. He disagreed with Mr. Grosskopf's calculated 46-year life because the book depreciation composite rate approved by the Commission is designed to recover any future accruals over the remaining book life of the underlying assets.

Mr. McCuen testified that NIPSCO suggested using an amortization period of 46 years using an ARAM approach because the Commission had previously concluded that all excess deferred taxes should be passed back using ARAM, noting that the Commission took into account that there are both "protected" and "unprotected" deferred taxes. Mr. McCuen explained several reasons why a shorter amortization period such as the five-year period recommended by Industrial Group witness Gorman or the OUCC's seven-year proposal is not appropriate. He testified that the WACC will increase at a faster rate with a rapid flow back of EDIT. The negative cash flow implications for NIPSCO may result in degradation of credit ratings which will increase financing costs and ultimately the WACC.

Mr. McCuen disagreed with Industrial Group witness Gorman that a 5.75% Indiana income tax rate should be used because the revenue requirement is based on revenue that spreads over the entire calendar year 2018. He explained that NIPSCO used the average Indiana corporate income tax rate in effect during the Forward Test Year, an approach that was approved by the Commission in NIPSCO's most recent electric rate case. He stated that using the Indiana Code's method, the Indiana state tax rate for calendar year 2018, would result in a 5.875% tax rate as NIPSCO originally proposed.

Mr. McCuen testified that NIPSCO is required to return the $6.4 million of excess deferred state income taxes over the remaining life of the underlying property consistent with both Sections 167 and 168 of the Internal Revenue Code and Ind. Code § 6-3-1-11. He disagreed with Mr. Gorman that there are no restrictions on the pass back of Indiana excess deferred taxes. He also disagreed with Mr. Gorman that NIPSCO should amortize excess state income taxes over a five-year period because that approach would be inconsistent with past practice and would create a normalization violation.

Mr. McCuen disagreed with Mr. Gorman's proposal that the amount of excess state income tax should be $12.7 million because the $6.4 million that is in the books and records as of December 31, 2018, is the only applicable amount. He testified that as the underlying timing differences change, NIPSCO receives a tax deduction at the state income tax rate in effect that year. The tax benefit at the current state income tax rate goes to the ratepayer.

H. **Mr. Rea.** In Mr. Rea's rebuttal testimony, he updated his cost of equity analysis to include data through January 2018. He explained that the updated analysis confirmed the reasonableness of his original 10.70% cost of equity. He asserted that the other parties' witnesses ignored substantial evidence that the Federal Reserve is gradually moving towards higher long-term interest rates that are consistent with a higher cost of equity. He also noted that the other parties' witnesses failed to acknowledge the negative effects of the 2017 Tax Act.

Mr. Rea testified that out of 113 gas utility ROE determinations from January 2013 through December 2017, only eight decisions granted a ROE at or below the OUCC's recommended ROE of 9.00%. He explained that the average authorized ROE granted to gas utilities has trended higher recently. A return as low as that recommended by the OUCC would make it difficult to compete for investor capital, and it would jeopardize NIPSCO's ability to make critical infrastructure investments.

Mr. Rea asserted that the opposing witnesses ignored the negative effects that the 2017 Tax Act has on utility cash flow credit metrics. He noted that in view of the expected deterioration in utility cash flow credit metrics as a result of the 2017 Tax Act, on January 19, 2018, Moody's revised its ratings outlooks for 24 regulated utilities and utility holding companies from stable to negative. He reported that Moody's discussed potential mitigation actions, including regulatory approaches and rate treatments that would appropriately address the refunding of excess ADIT to customers in a balanced and constructive manner. He explained that one mitigating action that could be taken by a utility to shore-up its credit metrics would be to issue additional common equity, which would result in an increase in the supply of common equity shares and could cause the expected return to increase.

I. **Mr. Amen.** Mr. Amen testified that NIPSCO's transmission system provides increased supply diversity, price options, and transfers supply across NIPSCO's pipeline system. The system also increases redundancy to provide secondary feeds, maintains higher allowed operating pressure, and provides additional physical paths for less supply source restrictions. He stated that the operational improvements in recent years, cost-saving supply sourcing flexibility, and associated pricing options were influential in his recommendation that the P&A allocation method be used for NIPSCO's transmission system mains.

Mr. Amen testified NIPSCO is not opposed to a bifurcated transportation tariff similar in approach to SDI witness Higgins's proposed rate structure, provided that it is supported by NIPSCO's Schedule 428/128 customers. He sponsored an alternative ACOSS, Schedule 428/128 revenue allocation, and bifurcated rate design in his rebuttal testimony. He explained that because of the greater variance in the annual throughput and load factor characteristics of its large use customers, NIPSCO prefers a rate design for Schedule 428/128 that considers both annual demand and load factor. He recommended that NIPSCO's proposed demand charges for Schedules 428/128 and 438 be approved by the Commission.

Mr. Amen testified that the range of residential monthly customer charge levels across the U.S. from the AGA Energy Analysis report ("AGA Study"), as well as the two midwestern regions surveyed by Black & Veatch, indicate a range of cost differences and costing methodologies employed by gas utilities and related cost recovery policies by state regulatory bodies. He noted that modest growth has occurred in the median level of residential monthly customer charges since 2015. Survey data supports progress by utilities in matching customer-related costs with the corresponding fixed charges through which those costs are recovered.

Mr. Amen recommended approval by the Commission of the following: (i) the revenue apportionment and rate design for the Step One revenue requirement of $409,981,113 (presented in Pet. Ex. 15-R, Attach. 15-F-R and 15-G-R); (ii) the ACOSS results presented for NIPSCO's Step Two revenue requirement of $436,585,562 (summarized in Pet. Ex. 15-R, Attach. 15-B-R); and (iii) the corresponding revenue apportionment and rate design (presented in Pet. Ex. 15-R, Attach. 15-C-R).

J. **Mr. Westerhausen.** Mr. Westerhausen testified NIPSCO's Proposed Tariff had been updated with final rebuttal rates for the 2018 forecasted Forward Test Year. He also explained NIPSCO's proposal to restructure Rate 115 into a single block rate from the existing two block structure. Mr. Westerhausen testified NIPSCO is proposing to put interim rates into effect upon approval by the Commission, based upon NIPSCO's current projections of utility plant in-service, associated depreciation, and capital structure at May 31, 2018.

Mr. Westerhausen also supported NIPSCO's proposal to utilize the allocators contained in Pet. Ex. 16-R, Attach. 16-R-C. This allocation of gas FMCA costs is included for recovery in the gas FMCA proposed in the Gas FMCA Proceeding to insure that the allocation in the tracker is consistent with the allocation of these types of costs in this rate case. He explained that transmission and distribution allocators are the margin allocation of margin requirement of these types of costs in the ACOSS model. The storage allocator is a combination of the allocation of storage and LNG margin requirements.

Mr. Westerhausen testified NIPSCO is proposing to utilize the allocators contained in Pet. Ex. 16-R, Attach. 16-R-D for future gas TDSIC filings, which is based on the revenue allocation to base rates. Witness Amen presented the proposed margin by rate in Pet. Ex. 15-R, Attach. 15-C-R and the gas costs in Pet. Ex. 15-R, Attach. 15-B-R.

Mr. Westerhausen supported Pet. Ex. 3-R, Adjust. REV 1D-R-18R to decrease the 2018 operating revenues by $16,799,080 to reflect the changes related to the 2017 Tax Act on the current 400 Series base rates and 2018 TDSIC revenues. He explained that the total reduction of $10,085,463 was allocated proportionately to the rate classes by rate class margins, and it was then divided by the rate class total sales in therms to get the reduction in the rate classes distribution or transportation charges. The distribution or transportation adjustments were then made to each block of the specific rates to obtain the new distribution and transportation rates. The tax adjusted rates were then utilized by Mr. Amen as the 400 Series rates to calculate 2018 margins. Ms. Konold also adjusted the TDSIC revenue by rate to account for the tax rate change. This adjusted TDSIC revenue was incorporated by Mr. Amen in his calculation of the 2018 total margins.

K. Mr. Baryenbruch. Mr. Baryenbruch, President of Baryenbruch & Company, LLC, presented the results of a study that evaluated the services provided by NCSC to NIPSCO during the twelve months ending December 31, 2016. He responded to Industrial Group witness Gorman's recommendation of a $9.5 million reduction of NCSC O&M charges for ratemaking purposes. He explained that Mr. Gorman had essentially prescribed that NCSC O&M charges to NIPSCO 2016 through 2018 should remain the same as the average charges for 2012 through 2015. Mr. Baryenbruch testified that Mr. Gorman provided no supporting analysis to substantiate his recommendation and made no attempt to evaluate changes in the makeup of NCSC services from 2012 through 2016. He testified that he reviewed and investigated the explanation of changes in NCSC O&M billings to NIPSCO between 2016 Actual to 2018 Forecast. He concluded the reasons for the overall increase in charges are in line with the experiences of his other utility clients with service company affiliates.

Mr. Baryenbruch conducted a comprehensive study of NCSC services and charges to determine the reasonableness of affiliate charges for services provided to NIPSCO during 2016. He provided testimony that addressed his evaluation of reasonableness based on consideration of the following four questions: (i) whether 2016 administrative and general charges to NIPSCO are reasonable compared to other utility service companies; (ii) whether NCSC provided services to NIPSCO at the lower of cost or market during 2016; (iii) whether the 2016 cost of NCSC's customer accounts services are comparable to those of other utilities; and (iv) whether the services NIPSCO received from NCSC were necessary. He testified that the study's overall results demonstrated that NIPSCO's 2016 service-related charges from NCSC were reasonable.

15. Testimony in Support of Settlement. On April 20, 2018, NIPSCO, the OUCC, the Industrial Group, GSG, SDI, EDFES, and Direct Energy (the "Settling Parties") filed the

Settlement. NIPSCO, the OUCC, the Industrial Group, and SDI filed testimony in support of the Settlement as follows:

A. **Mr. Shambo.** On behalf of NIPSCO, Mr. Shambo testified the Settlement documents an agreement reached between NIPSCO and its stakeholders that addresses the issues raised in both Cause No. 44988 (this gas rate case) and Cause No. 45007 (the Gas FMCA Proceeding). He stated that while the Settlement is not unanimous, it is comprehensive in scope, and it proposes resolution to all issues in both cases.

Mr. Shambo testified NIPSCO followed an open and transparent process in both cases to communicate details of its proposals and the rationale and support behind them. Meetings were conducted with NIPSCO's stakeholders beginning well in advance of the filing of each case, and information was provided throughout the process, leading to the submission of the Settlement to the Commission. He notes that NIPSCO responded to hundreds of data requests and informal requests for information and conducted a wide range of informational and settlement discussions. The result is a Settlement that reflects input from and the interests of a broad range of customer and industry groups.

Mr. Shambo identified the following key issues addressed by the Settlement in this proceeding:

- It provides NIPSCO with an increase in rate revenue sufficient to enable it to meet its revenue requirement and provide an adequate return on the investments made on behalf of its customers;

- It resolves a range of issues for NIPSCO's gas utility and its customers concerning the implementation of provisions of the 2017 Tax Act, including the treatment of ADIT and the timing of the pass back of excess deferred taxes;

- It changes the way that some of NIPSCO's gas rates function including the introduction of a demand charge component to its transportation rates and recognition of differences in transportation service provided from pipelines of different pressures (Rate 128); and

- It simplifies NIPSCO's tariffs in the interest of clarity and simplicity to the benefit of both NIPSCO and its customers. The Settling Parties agreed to the following: (i) revisions to Rule 13 related to curtailments; (ii) revisions to Rates 128 and 138 to address concerns regarding nomination and meter cap restrictions without calling a Critical Period; (iii) modifications to proposed balancing charge tiers; (iv) capping the increase to the bank capacity charge at 25%; (v) clarifications to Rider 131 regarding the 2% imbalancing buffer; and (vi) modifications to the proposed critical overtake and undertake penalties.

He also identified the key issues addressed by the Settlement with respect to its proposed Pipeline Plan and associated FMCA in the Gas FMCA Proceeding:

- It establishes that each component of the Pipeline Plan, including those incorporated from Cause No. 44988, is being undertaken in response to federally mandated pipeline safety performance standards;

- It establishes that costs associated with the Pipeline Plan are eligible for ratemaking treatment under Ind. Code ch. 8-1-8.4;

- It establishes the cost estimates for the Pipeline Plan; and

- It provides for ratemaking treatment and recovery of costs associated with the Pipeline Plan that allows flexibility for NIPSCO in execution but limits customer exposure to certain cost increases.

Mr. Shambo testified the Settlement represents the result of negotiation and compromise among the Settling Parties. He stated that there has been a high degree of interaction, negotiation, and compromise between and among the Settling Parties representing NIPSCO's large and small customers, its gas marketers and transportation pool operators, and its workforce. He testified the Settlement reached is consistent with the public interest. The regulatory compact is by necessity a balancing of interests between the utility and its stakeholders. He explained that negotiated resolutions to complex issues are consistent with the public interest because the result is the byproduct of input and compromise by the various parties that are directly impacted by the outcome. He stated that NIPSCO was able to reach an agreement that provides it with rates and charges sufficient to allow it to recover the cost of providing service to its customers and to a return of and on its investments in plant and equipment needed to serve its customers.

Mr. Shambo described three examples of the balancing of interests inherent in the regulatory compact and the public interest that are reflected in the Settlement. First, the Settlement provides for a verifiable process that allows for the transition of those investments into NIPSCO's rate base in a way that avoids protracted and costly litigation. Second, the Settlement provides NIPSCO with the opportunity to recover costs that advance its pipeline safety initiatives both in its base rates as well as through its Pipeline Plan. Third, the Settling Parties were able to resolve all of the issues associated with the implementation of the rate changes contemplated by the Settlement, including reaching agreement on critical issues related to the timing of the proposed three-step rate changes.

Mr. Shambo testified the resolution of the various issues addressed in the Settlement are well within the boundaries of the evidence submitted by NIPSCO and its stakeholders, including detailed ratemaking and accounting schedules that document the agreed-upon result. Mr. Shambo recommended that the Commission approve the Settlement as submitted.

B. Ms. Konold. On behalf of NIPSCO, Ms. Konold explained the three-step process. She testified that the Settling Parties agree that NIPSCO should be authorized to increase basic rates and charges. She explained that the first change in rates will be based on the agreed revenue requirement as adjusted to reflect the original cost of NIPSCO's net utility plant in-service, actual capital structure, and associated depreciation expense as of June 30, 2018 (Step One); the second change in rates will be based on the agreed revenue requirement as of December 31, 2018, as adjusted, if necessary, to reflect the lesser of the following: (i) NIPSCO's forecasted test-year-end rate base as updated in its rebuttal evidence ($1,520,209,700), or (ii) NIPSCO's certified test-year-end net plant in-service as of December 31, 2018 (Step Two); and the third change in rates will be to pass back unprotected excess ADIT to customers beginning January 1, 2020, over a 12-year amortization period (Step Three).

Ms. Konold testified that the Step One revenue requirement reflects NIPSCO's projected net utility plant in-service, projected capital structure, and the associated depreciation and amortization expense as of June 30, 2018, and it does not contain the pass back of the unprotected ADIT. Step One rates will go into effect on October 1, 2018. The Step Two revenue requirement reflects NIPSCO's projected net utility plant in-service, projected capital structure, and the associated depreciation and amortization expense as of December 31, 2018, and it does not contain the pass back of the unprotected excess ADIT. Step Two rates will go into effect on the date that NIPSCO certifies its test-year-end net plant in-service, or January 1, 2019, whichever is later. The Step Three revenue requirement reflects NIPSCO's projected net utility plant in-service, projected capital structure, and the associated depreciation and amortization expense as of December 31, 2018, and it contains the pass back of the unprotected excess ADIT. Step Three rates will go into effect on January 1, 2020, based on a compliance filing to be made by NIPSCO prior to that date.

Ms. Konold testified that the Settling Parties agreed to several adjustments resulting in differences between NIPSCO's case-in-chief, supplemental direct, and rebuttal positions. She explained that NIPSCO proposes to recover the gross revenue amount of $726,671,093 which reflects a revenue increase of $107,300,001 as compared to test year pro forma results based on current rates. She testified that gross revenue will provide NIPSCO the opportunity to earn net operating income of $98,813,631, and that the agreed revenue requirement reflects a reduction of $48,958,762 from NIPSCO's case-in-chief proposal of $775,629,855 and a reduction of $26,822,088 from NIPSCO's rebuttal proposal of $753,493,181. She also provided support for the Step Three revenue requirement through schedules supporting the calculation of NIPSCO's revenue requirement based on the 12-month period ending December 31, 2018. Ms. Konold provided testimony and attachments that explained the nature and calculation of each adjustment required to reflect the agreement of the Settling Parties and to implement each of the three steps contemplated by the Settlement, including the calculation of the agreed revenue requirement and the resulting authorized NOI.

C. <u>Mr. Westerhausen</u>. On behalf of NIPSCO, Mr. Westerhausen also testified that the Settling Parties agree that NIPSCO should be authorized to increase its basic rates and charges for natural gas utility service in three steps. Mr. Westerhausen sponsored the following: (i) clean and redlined versions of the Settlement Tariff; (ii) clean and redlined versions of the standard agreement for Gas Service for Rates 125, 128, and 138; (iii) illustrative rates for Step One, Step Two, and Step Three; and (iv) the 100 Series revenue proof. He testified that the rates and charges were revised consistent with the agreed-to base revenue of $388,988,600 (Step One) and class allocations contained within the Settlement. He presented a high-level summary of the changes in each rate schedule.[21] Mr. Westerhausen testified the standard agreement has been revised to reflect the legal name changed to Northern Indiana Public Service Company LLC and to reflect the addition of the subclasses for Rate 128. Exhibit A to the standard agreement was

[21] The allocation of pipeline and storage costs for the Gas Cost Adjustment are shown in Petitioner's Exhibit No. 15, Attachment 15-E (Allocation of Pipeline and Storage Costs for GCA).

revised to achieve the following: (i) update Curtailment Threshold level one; (ii) remove Curtailment Threshold level two; and (iii) reflect that the Billing Demand will be recalculated annually.

D. Mr. Grosskopf. On behalf of the OUCC, Mr. Grosskopf testified the Settlement resolves all issues between the Settling Parties. To highlight why the public interest is served by the Settlement, he focused on discussing differences between NIPSCO and the OUCC that were resolved by compromises reflected in the Settlement.

He stated that some of the ratepayer benefits in the Settlement are as follows: (i) resolved phase-in treatment of NIPSCO's original cost rate base, providing the OUCC and other intervenors with 60 days to review NIPSCO's Step Two rate base certification; (ii) established an agreement on NIPSCO's ROE, creating savings to ratepayers; and (iii) reached an accord on certain pro forma operating revenue and expense adjustments, with an overall reduction of approximately $11 million to NIPSCO's O&M expense request.

He stated that the Settlement resolves NIPSCO's Phase One and Two tax relief in Cause No. 45032, the Commission's investigation into the effects of the 2017 Tax Act on utility base rates, as well as the proposals made in NIPSCO's FMCA Cause No. 45007. He testified the Settlement also represents a compromise reached in the settlement negotiation process, with give and take by all of the Settling Parties. Mr. Grosskopf testified the Settling Parties devoted considerable time and effort to fairly balance NIPSCO's interests and those of the ratepayers.

Mr. Grosskopf testified NIPSCO proposed a 10.70% cost of equity in its direct case, while the OUCC proposed a 9.00% cost of equity. He stated the Settling Parties agreed to a 9.85% cost of equity for NIPSCO. The OUCC considers this a fair and reasonable result when combined with other considerations and compromises made in the Settlement.

Mr. Grosskopf testified NIPSCO's original cost rate base in its direct case was $1,482,818,488, including inventory and the TDSIC regulatory asset, which was updated to $1,520,209,700 in rebuttal. NIPSCO proposed that when setting Step Two rates at December 31, 2018, NIPSCO would true-up the amount of its projected rate base from its rebuttal testimony to the actual amount. In the Settlement, the Settling Parties agreed that, for purposes of setting Step Two rates, NIPSCO's rebuttal rate base amount is a not-to-exceed number.

Mr. Grosskopf testified NIPSCO originally proposed to use a NOI based on a fair value rate base for purposes of the earnings test in NIPSCO's GCA proceedings. The OUCC argued against this proposal. In the Settlement, NIPSCO agreed to continue with a NOI based on an original cost rate base for purposes of the GCA earnings test.

Mr. Grosskopf testified the OUCC proposed an increase of $4,012,115 to retail sales revenue. The Settling Parties agreed to increase present rate revenues by this amount, allocated to the residential, commercial, and small industrial interruptible customer classes.

Mr. Grosskopf testified the Settling Parties accepted NIPSCO's proposed depreciation rates. He stated that the increase in utility plant in-service since NIPSCO's last rate case together with the increase in depreciation rates in the Depreciation Study, and the termination of NIPSCO's depreciation credit, all combine to produce an increase in depreciation expense of nearly $58 million. He noted that this is a significant portion of the overall revenue increase in this Cause.

Mr. Grosskopf testified the Settling Parties have agreed to amortize NIPSCO's TDSIC regulatory asset and rate case expense over seven years rather than four years as originally proposed by NIPSCO. In addition, NIPSCO agreed to reduce rate case expense by $140,000, or $20,000 annually over seven years.

Mr. Grosskopf testified the Settling Parties negotiated compromises to various O&M expense adjustments. He stated that in testimony, the OUCC proposed adjustments to NIPSCO's charitable contributions, advertising, and lobby expense, and took issue with NIPSCO's proposed salary and wage expense. In addition, the OUCC proposed several adjustments to various gas operations expenses proposed in NIPSCO's direct case. He stated that to address some of the gas operations expenses, the Settling Parties agreed to remove approximately $3.2 million of proposed gas operations programs from NIPSCO's revenue requirements and allow recovery of these expenses in NIPSCO's FMCA Cause No. 45007. The $3.2 million is associated with transmission and distribution maximum allowable operating pressure projects, transmission risk modeling, legacy cross-bore inspection, and test station casing program expenses. The Settling Parties also negotiated an unspecified decrease of nearly $6 million to NIPSCO's total O&M expense. In total, the Settlement removes nearly $11.5 million from NIPSCO's proposed revenue requirement in its direct case, which also provides NIPSCO with $11.6 million in additional funding for gas operations. The Settling Parties believe this constitutes a fair and reasonable result for all parties.

Mr. Grosskopf testified that $3.2 million in specified projects moved into the FMCA from NIPSCO's proposed revenue requirement in this Cause. The Settling Parties agreed that the projects NIPSCO requested in Cause No. 45007 are federally mandated and should be approved as eligible for recovery through the FMCA. He stated the Settlement further stipulates that NIPSCO's cost recovery for each FMCA project within the proposed compliance plan is limited to the proposed cost estimate plus a 15% cap. The Settling Parties agree that any amounts over the 15% cap up to 25% will be deferred for recovery in NIPSCO's next base rate case. Any amount above 25% will be deferred and require specific justification and specific Commission approval for recovery in NIPSCO's next base rate case.

Mr. Grosskopf testified that the OUCC and Industrial Group are both parties in Cause No. 45007, and they have reviewed and conducted discovery about the proposals made in NIPSCO's direct case. NIPSCO's proposed FMCA tracker will provide funding for federally mandated pipeline safety projects, while NIPSCO also proposed to include O&M expenses related to the FMCA capital projects in its base rates. He stated that by including terms that resolve the issues in Cause No. 45007 in the Settlement in this Cause, the Settling Parties were able to forego the need to separately litigate what are integrated and related issues and cost recovery requests. He testified the Settlement provides ratepayer protection in the form of the 15% FMCA project cost recovery cap while balancing NIPSCO's interest in meeting federally mandated compliance requirements.

Mr. Grosskopf testified that in its supplemental filing, NIPSCO filed a proposal to refund its entire $97,913,573 excess ADIT balance over an amortization period of approximately 46 years, at a rate of 2.18%, regardless of how the ADIT was classified. The OUCC recommended excess ADIT be classified as either protected ($24,169,649) or unprotected ($73,743,924) and that the protected balance be amortized over a revised 42.3 year amortization period, with the unprotected balance amortized over seven years. For the Settlement, the Settling Parties agreed to amortize $24.2 million of protected excess ADIT over the timeframe NIPSCO proposed, approximately 46 years, and further agreed that, starting on January 1, 2020, the $73.7 million of unprotected excess ADIT will be amortized over 12 years. NIPSCO will make a compliance filing in late 2019 to show the calculation of the reduced rates as a result of the amortization of the unprotected excess ADIT.

Mr. Grosskopf testified it is the Settling Parties' intent that all of NIPSCO's tax issues applicable to Cause No. 45032 be resolved in this Cause. NIPSCO made its 30-Day filing on March 26, 2018, to resolve the reduction of the federal income tax to the 21% rate, in accordance with Phase One of the tax investigation. The Settling Parties agreed NIPSCO will return excess income tax recovered from January 1, 2018, through the date new rates go into effect in its TDSIC-9 filing, to be filed on or before September 1, 2018. The stipulations reached regarding the return of excess tax recovery through the TDSIC and the return of excess ADIT should resolve all Phase Two issues of the tax investigation for NIPSCO. Per the Settlement, NIPSCO agreed not to file for a sub-docket in Cause No. 45032.

Mr. Grosskopf testified that the calculation of the Commission Fee, URT, and State Income Tax are all affected by the Settlement. He stated that agreed changes to the revenue requirement will flow through these tax calculations, as reflected in Joint Exhibits A, B, and C to the Settlement.

Mr. Grosskopf testified the OUCC recommends Commission approval of the Settlement. He stated the Settling Parties each made material concessions when they entered into the proposed Settlement, resulting in savings to ratepayers of nearly $50 million, based on Step Three rates. The Settlement terms demonstrate the give and take of settlement negotiations, which resolve multiple contested issues in more than one docketed case in a manner acceptable to all Settling Parties. The Settlement also results in efficiencies and reduces the risk and expense of litigating multiple issues. Therefore, the OUCC considers the Settlement to be in the public interest, and the OUCC recommends the Commission approve the Settlement.

E. <u>**Mr. Rutter.**</u> On behalf of the OUCC, Mr. Rutter testified that if the Settlement is approved, it will provide certainty regarding critical issues, including revenue requirements, authorized return, and the allocation of NIPSCO's revenue requirements among its various rate classes.

While this Settlement is the result of compromise between the Settling Parties and represents a balance of the interests of NIPSCO and its ratepayers, there are many ratepayer benefits outlined in the Settlement. Based on Step Three rates, there is a reduction of $48,958,762 in the revenue requirement originally requested by NIPSCO. The revenue requirement to be allocated among the various rate classes assumes a modified across-the-board margin increase for residential customers of 36.21% with no rate class experiencing a margin increase greater than the 38.98% increase for Rate 128 – Large Firm Transportation and Balancing Service. Mr. Rutter opined that the rates developed to recover the revenue requirement adopted by the Settling Parties and reflected in the Settlement are fair, reasonable, and consistent with cost causation principles. The customer charge of $14.00 for residential customers (Rate 111) is reduced from NIPSCO's originally filed $19.50 customer charge. There is agreement on the allocation factors by rate class to be adopted for use in NIPSCO's Cause No. 45007, and the Settling Parties intend for the Settlement to resolve all issues in the Cause No. 45007 docket.

Mr. Rutter testified NIPSCO witness Mr. Ronald J. Amen presented an ACOSS based on the P&A allocation methodology. The OUCC concurred with use of a P&A allocation methodology in this proceeding. He testified the Settlement eliminates the need to litigate which allocation methodology is best, and adopts, for settlement purposes, a modified across-the-board margin increase approach using the P&A allocation methodology to establish the margins by rate class under existing rates.

Mr. Rutter testified the OUCC supports the use of a modified across-the-board margin increase based on the overall system average margin increase of 36.21% for settlement purposes. The use of a modified across-the-board margin increase facilitated the adoption of a Settlement that will allow ratepayers to realize the benefits inherent in the Settlement.

Mr. Rutter sponsored Attachment ETR S-1 showing the decrease to the overall margin increase from NIPSCO's filed margin increase of 47.34% to the overall margin increase of 36.21% as a result of the Settlement. He stated that NIPSCO's filed rate class margin increase ranged from a low of 9.58% to a high of 70.51%. The Settlement narrowed the band between high and low margin increase from a low of 2.72% to a high of 38.98%.

Mr. Rutter testified the Settlement resolved the dispute over all fixed monthly charges. He stated that from the OUCC's perspective, resolution on the monthly customer charge under Rate 111 – Residential Service was a primary focus. NIPSCO proposed a monthly customer charge of $19.50 in its case-in-chief, and the OUCC responded in its case with an increase of $13.75. The Settling Parties agreed on a customer charge for residential customers of $14.00.

Mr. Rutter testified the OUCC's testimony in this Cause showed that NIPSCO's proposed residential customer charge of $19.50 was an outlier as compared to the fixed monthly charge levied by other gas utilities in the state – indeed in the United States – as shown by the AGA Study. As a result of compromise and the give and take involved in settlement negotiations, the Settling Parties agreed to a $14.00 residential customer charge, which is within the range of other existing fixed customer charges for residential gas customers in the state. Mr. Rutter opined that this result is a reasonable balance between interests of the ratepayer and the utility.

Mr. Rutter testified the proposed allocation factors for use in NIPSCO's FMCA Tracker Cause No. 45007 were negotiated between the Settling Parties as part of the overall settlement discussions and resolution. The Settling Parties agree these allocation factors will be used pursuant to the provisions of Ind. Code ch. 8-1-8.4 in seeking ratemaking treatment for associated Compliance Plan costs.

Mr. Rutter testified the proposed allocation factors for use in NIPSCO's TDSIC tracker detailed are the result of the Settling Parties' agreement. Mr. Rutter opined that applying those allocators to NIPSCO's gas TDSIC is consistent with Ind. Code § 8-1-39-9(a)(1) and the Commission's Order in Cause No. 44403-TDSIC-3, which states that gas TDSIC costs should be allocated based on total revenue, including gas cost revenue.

F. **Mr. Phillips.** On behalf of the Industrial Group, Mr. Phillips noted that the Settlement is a comprehensive agreement that resolves the revenue, complex allocation, and rate design issues in this case. The Settlement is a result of arms-length negotiations between the Settling Parties to reach a comprehensive settlement that resolves all issues raised. He opined that the Settlement is well within the range of outcomes from a litigated case.

Mr. Phillips stated that he believes the Settlement should be approved. The Settlement is fair, reasonable, and in the public interest. It lowers NIPSCO's ROE to 9.85%. The overall revenue increase is over $48.96 million less than NIPSCO proposed in its direct testimony. The Settlement mitigates the increase to all customer classes and results in a significantly lower percentage increase to all classes than NIPSCO's direct testimony. It addresses rate design issues for the 128 and 138 classes. It also addresses NIPSCO's proposed FMCA, and it addresses the allocation and cost recovery of NIPSCO's compliance plan, as well as the allocations for future TDSIC trackers. Finally, the Settlement reflects compromises on tariff issues.

G. **Mr. Higgins.** On behalf of SDI, Mr. Higgins testified that the Settlement includes a reduction in the overall revenue requirement and a reasonable revenue allocation across classes that represents an appropriate balancing of interests between the Settling Parties. He testified that the Settlement also provides reasonable terms for passing on the benefits of the 2017 Tax Act to customers. The Settlement establishes differentiated rates for high pressure and distribution pressure service within Rate 128 as a meaningful first step toward reflecting the lower cost to serve Rate 128 customers that are directly connected to the high pressure system.

Mr. Higgins testified that by splitting Rate 128 into two sub-groups to reflect the distinct cost allocation between customers served exclusively from facilities at 60 PSIG or above from those taking service at lower distribution pressure (Rate 128 DP), the agreed-upon rate design will result in a lower demand charge and first block transportation charge for Rate 128 HP customers than for Rate 128 DP customers with no impact on any other rate classes. He explained that it is appropriate to reflect the lower cost to serve customers that are directly connected to the high pressure system since these customers do not use the downstream distribution mains. NIPSCO properly recognizes that a significant proportion of the gas delivered to Rate 128 customers is delivered directly to customers from the high pressure system, not the downstream lower pressure system, in its class cost-of-service study submitted in this proceeding.

Mr. Higgins testified that the pressure differentiated rate structure provided for in the Settlement addresses this intra-class subsidy by providing a lower demand charge and lower first block transportation charge for HP customers than for DP customers in partial recognition of the lower cost to serve the HP customers. This represents an important first step toward remedying the intra-class subsidy within Rate 128, while mitigating the impact on distribution pressure customers that may result from reflecting the full cost-based difference between these two sub-rates in a single step. Mr. Higgins opined that the Rate 128 rate design proposed in the Settlement represents a reasonable compromise for the purpose of implementing pressure-differentiated rates at this time.

16. **Testimony Opposing the Settlement.** On May 14, 2018, Mr. Olson, on behalf of the CAC, testified. Mr. Olson opposed one condition of the Settlement relating to the proposed increase in the monthly fixed customer charge from the current rate of $11.00 per residential customer to the rate of $14.00 per residential customer. Mr. Olson stated that this represents a 27%

increase in the fixed customer charge and it is significantly out of proportion to the other proposed rate increases in this case. He stated that the Settling Parties provided no evidence justifying the proposed increase, only that the number was achieved as the result of negotiation and compromise.

Mr. Olson noted that his arguments against the Settlement are the same as those he made in his direct testimony, and his arguments include the following: (i) a lack of justification; (ii) a regressive impact on low-use and low-income customers; (iii) not justified under sound economic principles and would not advance economic efficiency; and (iv) a disincentive for energy efficiency and other distributed energy resources. Mr. Olson argued that while the Settlement provides no justification for any increase in the fixed customer charge, the other impacts he raised in his prefiled direct testimony were mitigated somewhat by the reduced size of the increase.

He stated the compromise between NIPSCO and the Settling Parties is an inadequate foundation for the approval of the fixed customer charge increase. He claimed that there is no economic theory that economic efficiency is improved by modifying rate structure to align with cost structure. He concluded that given the weighty issues, the impact of the proposed rate change on many struggling families, the adverse policy consequences, and the lack of economic theory evidence to support the underlying Company proposal, the proposed increase in the fixed customer charge is not just and reasonable, and not in the public interest. He recommended that the Commission disapprove any proposed increase in a fixed customer charge, and allocate any revenue increase assigned to the residential class to the volumetric charge. He also recommended that the Commission initiate a discussion or investigation regarding policy options and rate design to find an alternative to increasing the fixed customer charge and adding more trackers.

17. <u>Settlement Reply Testimony</u>. On May 11, 2018, NIPSCO's Mr. Shambo filed a reply to CAC's opposition to the Settlement. Mr. Shambo pointed out that the increase in the monthly residential customer charge is supported by economic theory previously endorsed by the Commission as discussed in NIPSCO's case-in-chief, and is consistent with the public interest. He stated that the Commission has supported SFV rate design concepts whereby costs that are incurred, regardless of the amount of gas delivered, are recovered on a fixed, or per customer basis. Costs that vary based on the amount of gas delivered are recovered based on the amount delivered or on a variable basis. He stated this rate design is consistent with the way the underlying costs are caused, and as a result, this rate design sends the most accurate price signal to customers. Mr. Shambo explained why the accuracy of price signals is important. He stated that rates that are not derived based on cost causation, mismatch cost incurrence and cost recovery and provide customers with inaccurate price signals. Such mismatches provide both the utility and customers with perverse incentives relative to their level of consumption. For example, when fixed charges are recovered from customers on a volumetric basis, customers are rewarded with lower bills when consumption is reduced, but the same reduced consumption harms the utility because it necessarily under-recovers actual fixed costs that would otherwise have been captured in the consumption the customer has eliminated. The converse is also true. When variable costs are recovered through a fixed charge, the utility could recover more than its actual variable costs as customers reduce their consumption while the customers' savings are less than they should have otherwise been.

Mr. Shambo testified NIPSCO initially proposed a $19.50 residential monthly customer charge which was lower than a customer charge that would have recovered 100% of NIPSCO's fixed charges, and that proposal was supported by testimony in NIPSCO's case-in-chief. He noted that in particular, his direct testimony includes eight pages dedicated solely to the issue of fixed cost recovery. Mr. Shambo indicated that it is fair to say that various points of view on fixed charges have been thoroughly addressed in testimony. He stated that while no witness addressed the precise calculation of or negotiations around the agreed-upon $14.00 residential customer charge, the Settlement reflects the result of multi-party negotiations covering wide ranging and complex issues. He testified the agreed-upon $14.00 residential charge falls well below NIPSCO's litigation position of $19.50, and it is higher than the litigation positions of the CAC (no change) and the OUCC (no more than 50% of the overall average increase). Therefore, it is well within the range of support offered by the various parties to this proceeding.

Mr. Shambo reiterated that the regulatory compact is by necessity a balancing of interests between the utility and its stakeholders. Negotiated resolutions to complex issues are consistent with the public interest because the result is the byproduct of input and compromise by the various parties that are directly impacted by the outcome. He disagreed with Mr. Olson's view that the Settlement reached here does not meet that standard because it fails to reach the uncompromised position that CAC advocated. He opined it would be unreasonable for the Commission to revisit the overall resolution negotiated by seven Settling Parties to capture the position of one party on a single issue. He testified the Settlement reflects a balancing of interests consistent with the regulatory compact, it is supported by substantial evidence, and it should be approved as submitted.

18. Commission Discussion and Findings.

A. Settlement. Settlements presented to the Commission are not ordinary contracts between private parties. *U.S. Gypsum, Inc. v. Ind. Gas Co.*, 735 N.E.2d 790, 803 (Ind. 2000). When the Commission approves a settlement, that settlement "loses its status as a strictly private contract and takes on a public interest gloss." *Id.* (quoting *Citizens Action Coal. of Ind., Inc. v. PSI Energy, Inc.*, 664 N.E.2d 401, 406 (Ind. Ct. App. 1996)). Thus, the Commission "may not accept a settlement merely because the private parties are satisfied; rather [the Commission] must consider whether the public interest will be served by accepting the settlement." *Citizens Action Coal.*, 664 N.E.2d at 406.

Further, any Commission decision, ruling, or Order, including the approval of a settlement, must be supported by specific findings of fact and sufficient evidence. *U.S. Gypsum*, 735 N.E.2d at 795 (citing *Citizens Action Coal. of Ind., Inc. v. Pub. Serv. Co. of Ind., Inc.*, 582 N.E.2d 330, 331 (Ind. 1991)). The Commission's own procedural rules require that settlements be supported by probative evidence. 170 IAC 1-1.1-17(d). Therefore, before the Commission can approve the Settlement, we must determine whether the evidence in this Cause sufficiently supports the conclusions that the Settlement is reasonable, just, and consistent with the purpose of Ind. Code ch. 8-1-2, and that such agreement serves the public interest.

Our review of the reasonableness of the Settlement here is aided by both the comprehensive scope of Settling Parties' agreement as well as the extensive evidence of record that addresses competing positions on a wide range of issues including: (i) the value and update of NIPSCO's rate base; (ii) the allocation of costs among rate classes; (iii) the rate design to be employed; (iv) the cost of common equity; (v) calculation of NIPSCO's capital structure; and (vi) the financial basis for results at present, proposed, and settlement rates. Each of these issues was addressed in testimony that considered a range of proposed outcomes. The resolution of each issue is supported by an extensive evidentiary record in this Cause. In some instances, that support was unanimous, in others contested, but the evidentiary record provides a thorough consideration of the merits of the issue at hand, providing the Commission with a detailed record to examine the issues.

The rates agreed upon in the Settlement are lower than those originally proposed by NIPSCO in its case-in-chief. The Settlement resolves various issues in dispute between the Settling Parties that were identified in their respective evidentiary submissions. Specifically, the Settlement addresses NIPSCO's revenue forecasts, its rate base updates, the three-step implementation of rates under Ind. Code § 8-1-2-42.7, the appropriate ROE, and all the issues of cost allocation and rate design.

In particular, the Settlement reached among the Settling Parties with respect to the rate base cutoff dates and rate base updates provides a reasonable approach. It harmonizes the interplay between the "used and useful" standard and valuation of rate base as of the end of the Future Test Year on December 31, 2018, by providing certification of plant in-service prior to the implementation of rates.

We note that the Settlement also proposes resolution of certain issues initially raised in other proceedings pending before the Commission. Specifically, the Settlement proposes resolution of all regulatory and ratemaking issues associated with the passage and implementation of the 2017 Tax Act for NIPSCO's gas utility through the rate changes anticipated in this Cause. The Settlement also contemplates resolution of all issues associated with NIPSCO's proposed certificate of public convenience and necessity under Ind. Code ch. 8-1-8.4 in pending Cause No. 45007.

B. <u>Rate Base Cutoff and Update Mechanism</u>. The Settling Parties agreed to specified rate base cutoffs and update mechanisms discussed below. We find that the Settlement provisions regarding the rate base cutoff and update mechanism process are reasonable, supported by evidence of record, and are approved.

For purposes of this section, "certify" means NIPSCO has determined that it has completed the amount of net plant indicated in its certification and the corresponding net plant additions have been placed in-service and are used and useful in providing utility service as of the date of certification. NIPSCO will serve all Settling Parties with its certification. The OUCC and intervening parties will have 60 days from the date of certification to state any objections to NIPSCO's certified test-year-end net plant in-service. If there are objections, a hearing will be held to determine NIPSCO's actual test-year-end net plant in-service, and rates will be trued-up (with carrying charges) retroactive to the date that NIPSCO's Step Two rates became effective.

In accordance with the Settlement, NIPSCO will increase its basic rates and charges in the following three steps:

Step One Rates

- Step One Rates are based on the agreed revenue requirement as adjusted to reflect the original cost of NIPSCO's net utility plant in-service, actual capital structure, and associated depreciation expense as of June 30, 2018; and

- Assuming a Final Order date on or about September 24, 2018, Step One Rates will become effective on October 1, 2018.

Step Two Rates

- Step Two Rates are based on the agreed revenue requirement as of December 31, 2018, as adjusted, if necessary, to reflect the lesser of (a) NIPSCO's forecasted test-year-end rate base, as updated in its rebuttal evidence, of $1,520,209,700, or (b) NIPSCO's certified test-year-end net plant in-service as of December 31, 2018;

- Calculate the resulting Step Two rates using NIPSCO's actual capital structure as of December 31, 2018, subject to the provisions of the Settlement. Settlement at 6, Paragraph B.1.a; and
- Step Two Rates go into effect for usage beginning on the date that NIPSCO certifies its test-year-end net plant in-service, or January 1, 2019, whichever is later.

Step Three Rates

- Step Three Rates pass back unprotected excess ADIT to customers beginning January 1, 2020, on a straight-line basis over a 12-year amortization period; and

- NIPSCO will make a compliance filing in this Cause in late 2019 to show the calculation of the reduced rates.[22]

C. **Revenue Requirement.** The Settling Parties agreed the maximum revenue requirement for Step Three, the last of the three rate adjustment steps, will be $409,763,474 which represents gross margin and is net of all of gas costs. Gas costs will continue to be separately recovered through NIPSCO's GCA Mechanism. The Settling Parties agree that NIPSCO's base rates will be designed to produce a Revenue Requirement of no more than $726,671,093, less $6,855,023 of Other Revenues, which represents a decrease of $48,958,762 from the amount originally requested by NIPSCO.

The understanding on the appropriate revenue requirements for NIPSCO is based upon agreement among the Settling Parties regarding original cost rate base, capital structure, cost of capital, and operating expenses (including depreciation expense and tax expense). We find that the Settlement provisions regarding NIPSCO's revenue requirements are reasonable, supported by evidence of record, and are approved.

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[22] Joint Exhibit C, Statement of Operating Income, attached to the Settlement represents the schedules supporting the calculation of NIPSCO's revenue requirement based on the pass back of unprotected excess ADIT.

(1) NIPSCO's Rate Base. The Settling Parties have agreed that the original cost of NIPSCO's retail gas rate base of $1,520,209,700 (inclusive of gas in underground storage, materials, and supplies) and the TDSIC Regulatory Asset should be used for purposes of establishing rates in this case. The original cost value of NIPSCO's rate base is supported by NIPSCO's initial, supplemental, rebuttal, and settlement testimony. Neither the components nor value of that original cost rate base is disputed by any party. Accordingly, we find that NIPSCO's original cost rate base for purposes of this proceeding is $1,520,209,700, and that this original cost rate base should be used for purposes of Ind. Code § 8-1-2-6.

(2) Depreciation and Amortization Expenses. NIPSCO presented evidence from Mr. Spanos recommending depreciation accrual rates for gas plant assets calculated in accordance with the Depreciation Study he sponsored. No evidence was presented that disputed the results of Mr. Spanos's Depreciation Study or the resulting accrual rates. We find that the Settling Parties' agreement for the approval of those depreciation accrual rates is consistent with the evidence, is reasonable, and should be approved and incorporated for the determination of net plant in-service values for the calculation of Step One, Step Two, and Step Three rates. We note that NIPSCO should continue to use the depreciation rates applicable to its common plant consistent with the Settlement and in our Order in Cause No. 44688.

With respect to amortization expense, the evidentiary record includes proposals from NIPSCO, the OUCC, and the Industrial Group. They proposed competing approaches to the amortization and amount of the regulatory assets for rate case expense and for the amortization of the TDSIC deferred balance. The Settling Parties agreed to resolution of these issues, providing for the amortization of regulatory assets for rate case expense and the TDSIC deferred balance over seven years. For rate case expense, the Settling Parties stipulated that annual amortization expense shall reflect a reduction of $140,000 from that proposed in NIPSCO's case-in-chief and that if it has not been already addressed by an intervening base rate case Order, after the completion of the seven-year period, NIPSCO will make a tariff filing to reflect the reduction in amortization expense as a result of the end of rate case expense and TDSIC deferred balance amortization. We find this resolution to be reasonable and appropriate.

(3) Other Specific Ratemaking Issues. As discussed above, the Settling Parties agreed to a level of operating expenses to be incorporated in NIPSCO's revenue requirement with the exception of the specific ratemaking treatment to be accorded the following issues:

a. Tax Cut and Jobs Act of 2017. On January 3, 2018, the Commission issued an Order in Cause No. 45032 that initiated an investigation to review and consider the implications of the 2017 Tax Act on utility rates and to determine what additional action is warranted. NIPSCO was deemed one of many Respondents in that Cause. As directed in the February 16, 2018 Order (as clarified by the Commission's Docket Entry issued March 7, 2018) in that Cause, on March 26, 2018, NIPSCO filed with the Secretary of the Commission via the 30-day filing procedure set forth in 170 IAC 1-6, a revised gas tariff to reflect the effects of the change in federal income taxes implemented by the 2017 Tax Act as required by Phase One of that proceeding. The Commission approved NIPSCO's 30-Day Filing No. 50168 at Conference held on April 25, 2018.

In this proceeding, NIPSCO used the 12 months ended December 31, 2018, as the Future Test Year for establishing rates. Many tax changes in the 2017 Tax Act became effective as of January 1, 2018. We note that both the passage of the 2017 Tax Act and the initiation of our investigation in Cause No. 45032 occurred several months after the filing of the Petition here, and that by agreement of the Parties, NIPSCO supplemented its case-in-chief to account for the impact of the 2017 Tax Act on its Future Test Year. The Settlement provides that NIPSCO should be dismissed from Phase Two of Cause No. 45032 based on the proposed resolution of all issues related to the second Phase of that proceeding by resolving all issues pertaining to the treatment of ADIT.

The record reflects that as of December 31, 2017, NIPSCO recorded protected excess ADIT of $24,169,649. In the Settlement, the Settling Parties agreed that NIPSCO should continue to utilize the ARAM to pass savings back to customers and that NIPSCO should be authorized to record the differences between ARAM and the amortization passed back through base rates (estimated using a 45.8 year amortization period) as a regulatory asset or liability for treatment in NIPSCO's next base rate case. With respect to unprotected excess ADIT, NIPSCO recorded $73,743,924 as of December 31, 2017, and agreed to pass it back to customers beginning January 1, 2020, on a straight-line basis over a 12-year amortization period based on a compliance filing to be made in this Cause in late 2019 to show the calculation of the reduced rates to be effective beginning January 2020, in Step Three of the rate relief proposed in this Cause.

The resolution proposed for issues associated with the return of excess ADIT balances is supported by the uncontested evidence of record. The utilization of ARAM as the basis for the pass back of ADIT associated with protected assets is consistent with regulations promulgated by the U.S. Department of Treasury. The pass back of unprotected ADIT is subject to Commission discretion. As such, we are persuaded that the agreed pass back of excess unprotected ADIT over a 12-year period beginning in 2020 is a compromise given the parties' respective positions. We find the proposed treatment of ADIT balances as proposed by the Settling Parties to be reasonable and in the public interest.

b. Treatment of Capital Lease. NIPSCO's proposed Adjustment OM 7-18R to increase Forward Test Year operating expenses by $2,436,000 is for a capital lease relating to the NGPL - NIPSCO 134th Street Project. NIPSCO Witness Campbell discussed the specifics of the project. NIPSCO's budget accounts for the 134th Street Project lease as a capital lease, and the minimum lease payments were proposed to be recorded as interest expense and depreciation expense. This adjustment was not opposed by any party in the case, and on May 16, 2018 the Commission issued its final Order in Cause No. 45020 that granted NIPSCO modified financing authority and approved the accounting treatment for that capital lease. Upon consideration of this evidence, the Commission approves NIPSCO's requested treatment of this adjustment.

c. Regulatory Treatment of Current Gas ARP Margins. NIPSCO proposed and the Settling Parties agreed that the regulatory treatment of margins associated with NIPSCO's Current Gas ARP programs shall remain unchanged. No evidence of record proposes any other result, and we find that such margins shall continue to be included in the GCA NOI earnings test pursuant to Ind. Code §§ 8-1-2-42(g)(3)(C) and 8-1-2-42.3 except for the following: (i) GCIM (Rule 15), Capacity Release (Rule 16), and Optional Storage Service

Rider (Rider 142A), which shall be treated as below-the-line but shall continue to be shared with customers through the GCA as provided in the Current Gas ARP; (ii) NIPSCO's DependaBill program (Rate 151); and (iii) Price Protection Service (Rider 181).

(4) **<u>Rate of Return</u>.** We are charged with providing the utility with the opportunity to earn a fair return on the fair value of its property. *See Gary-Hobart Water Corp. v. Ind. Util. Reg. Comm'n*, 591 N.E.2d 649, 653-54 (Ind. Ct. App. 1992) and *Office of Util. Consumer Counselor v. Gary-Hobart Water Corp.*, 650 N.E.2d 1201 (Ind. Ct. App. 1995). One accepted way of doing this is to determine NIPSCO's actual capital structure, along with the cost of the various components of its capital, as the Settling Parties have done. NIPSCO has agreed that its weighted cost of capital times its original cost rate base yields a fair return for purposes of this case. The Settling Parties agreed that the following projected capital structure and cost of capital for NIPSCO should be used in setting rates in this case:

	% of Total	Cost %	WACC %
Common Equity	46.88%	9.85%	4.62%
Long-Term Debt	36.80%	4.94%	1.82%
Customer Deposits	1.22%	4.91%	0.06%
Deferred Income Taxes	21.10%	0.00%	0.00%
Prepaid Pension Asset	-7.43%	0.00%	0.00%
Post-Retirement Liability	1.39%	0.00%	0.00%
Post-1970 ITC	0.04%	7.69%	0.00%
Totals	**100.0%**		**6.50%**

The evidence of record indicates that this agreed-upon capital structure represents the projected capital structure of NIPSCO at December 31, 2018, including equity, long-term debt, customer deposits, deferred income taxes, PPA, post-retirement liability, and post-1970 ITC. No party disputed that the above capital structure represents the projected capital structure of NIPSCO at December 31, 2018, and under the terms of the Settlement Step One and Step Two rates will be certified based upon NIPSCO's actual capital structure and rate base as of June 30, 2018, and December 31, 2018, thus providing for rates that will be trued up to reflect actual conditions.

NIPSCO's evidence demonstrated that its embedded cost of long-term debt is projected to be 4.94%, its cost of customer deposits is projected to be 4.91%, and its post-1970 ITC is projected to be 7.69%. Deferred income taxes, post-retirement liability, and PPA should be treated as zero-cost capital.[23] No party disputed these projected values that will be subject to true up and certification under the Settlement.

With regard to NIPSCO's cost of equity, the evidence of record reflects a number of different methods of estimating NIPSCO's cost of equity. We recognize that the cost of equity cannot be precisely calculated and its estimation requires the use of judgment and the consideration of more than one methodology. The testimony of various witnesses in this case reflected initial

[23] We note that the Settlement is silent as to the capital structure to be applied in capital investment cost recovery tracking mechanisms. Therefore, any determination concerning this issue will be made in those future proceedings.

views that NIPSCO's cost of equity was between 9.0% and 10.95%, with the Settling Parties concluding that 9.85% was a reasonable cost of equity to use to set rates in this Cause.

Given due consideration to this evidence of record including the Settlement, we find that the agreed-upon cost of equity of 9.85% is within a reasonable range. We also find that use of a 9.85% cost of equity to set rates for NIPSCO is supported by the risks facing NIPSCO in particular and the gas utility industry generally, and is supported by the evidence demonstrating NIPSCO's reliability and customer service performance. Accordingly, we find that a 9.85% cost of equity, along with the other cost of capital components shown above, producing a WACC of 6.50% for NIPSCO, is reasonable in this Cause. The evidence of record indicates that this WACC, when applied to NIPSCO's rate base, produces a NOI of $98,813,631. We accordingly conclude that for purposes of the earnings test contained in the GCA statute, NIPSCO shall be authorized to earn a NOI of $98,813,631, prior to consideration of additional returns approved by the Commission in any future capital cost tracking proceeding.

(5) <u>Operating Income under Present Rates</u>. For the 12 months ending December 31, 2018, NIPSCO's projected jurisdictional operating income from its gas utility operations at current rates was shown by NIPSCO to be as follows:

Total Operating Revenue		$619,371,092
Less Total Gas Costs	$316,907,619	
Gross Margin		$302,463,473
Less Total Operations and Maintenance	192,612,338	
Less Total Depreciation Expense	$63,943,903	
Less Total Amortization Expense	$8,932,109	
Less Total Taxes Other Than Income	$26,963,350	
Less Federal and State Taxes	$(4,403,428)	
Total Operating Expenses including Income Taxes		$288,048,272
Net Operating Income		$14,415,201

NIPSCO's Attachment 3-A-S2.[24]

The evidence of record supports the conclusion that NIPSCO's current rates and charges are unjust, unreasonable, and inconsistent with the public interest. Therefore, NIPSCO shall be authorized to adjust its rates so as to permit the provision of reasonably adequate service and facilities at just and reasonable rates.

(6) <u>Rate Level To Be Authorized</u>. NIPSCO Witness Westerhausen sponsored Attachment 16-S-E, documenting the revenue proof and supporting the agreed-upon

[24] The values shown were provided in support of Petitioner's projected Step Two rates to be based on plant in-service and capital structure as of December 31, 2018, corresponding to the close of Petitioner's 2018 Forward Test Year.

revenues. In the Settlement, NIPSCO agreed that its weighted cost of capital times its original cost rate base yields a fair return for purposes of this case. Based upon this agreement, the Settling Parties agreed that NIPSCO should be authorized a fair rate of return of no more than $98,813,631, yielding a WACC for earnings test purposes of 6.50%, based upon the following: (i) an original cost rate base of $1,520,209,700, inclusive of gas in underground storage, materials, and supplies, and TDSIC Regulatory Asset as proposed in NIPSCO's case-in-chief; (ii) NIPSCO's capital structure; and (iii) an authorized ROE of 9.85%. Based on the foregoing, the Commission finds that NIPSCO should be authorized rates that are projected to produce operating revenue for Step One, Step Two, and Step Three, as follows:

	Step One	**Step Two**	**Step Three**
Operating Revenues	$705,896,219	$735,097,514	$726,671,093
Operating Expenses and Taxes			
Gas Costs	$316,907,619	$316,907,619	$316,907,619
Operating & Maintenance Expenses	$192,873,596	$192,961,768	$192,936,325
Depreciation Expense	$59,898,325	$63,943,903	$63,943,903
Amortization Expense	$7,913,043	$8,932,109	$8,932,109
Taxes Other Than Income Taxes	$28,289,856	$28,737,537	$28,608,352
Income Taxes	$19,989,666	$24,800,948	$16,529,154
Total Operating Expenses and Taxes	$308,964,486	$319,376,265	$310,949,843
Projected Net Operating Income	$80,024,114	$98,813,630	$98,813,631

As we discussed above, the projected results will be subject to certification and true-up under the Settlement for Step One and Step Two, but the Settling Parties have agreed that NIPSCO's authorized NOI should be no higher than $98,813,631.

(7) Revenue Allocation. The evidence of record includes proposals for the allocation of revenue by class presented by multiple parties. In settlement, the Settling Parties agreed to a modified across-the-board cost allocation methodology that is cost based and mitigates the impact on various customer classes in a manner that they determined to be reasonable. The Settlement revenue allocation for the third and final step of the proposed increase is summarized as follows:

Class	**Rate Schedule**	**Step Three Allocation**
Residential	Rate 111	36.21%
Multi-Family	Rate 115	2.72%
General Service - Small	Rate 121	37.70%
General Service - Large	Rate 125	27.47%
Large Transportation	Rate 128 – DP	48.03%
Large Transportation (High Pressure)	Rate 128 – HP	36.21%
General Transportation	Rate 138	38.93%

We have considered the evidence and the differences of opinion on the issue of cost allocation. We also considered the diverse nature of the positions taken by the Settling Parties, their willingness to agree to the proposed allocation of revenue, and the evidence supporting the proposed allocation. The Commission finds that the Settlement cost allocation methodology is appropriate for the development of NIPSCO's retail rates and charges in this case and is approved. The evidence of record indicates that the agreed upon cost allocation is based on a fully allocated cost of service study, mitigated so as not to unduly impact any one customer class. Further, the evidence of record demonstrates that the cost allocation contemplated by the Settlement will produce fair and reasonable rates for each class of customers. The Settling Parties collectively represent a diverse mix of customer and supplier interests that encompass all customer classes. Based upon all the evidence presented, we find the Settlement revenue allocation will produce just and reasonable rates under Ind. Code § 8-1-2-4.

(8) **Rate Design.** The Settling Parties agreed to maintain NIPSCO's existing rate structure. NIPSCO originally proposed an increase to the monthly customer charge (specifically, from \$11.00 to \$19.50 per residential customer under Rate 111). Under the terms of the Settlement, the monthly customer charge for residential Rate 111 would increase from \$11.00 to \$14.00, which, as the evidence shows, is a compromise between NIPSCO and the OUCC. It represents an increase less than the system average. The CAC was the only party in opposition to the proposed Settlement increase to the customer charge. Mr. Olson suggested that the Settlement is inconsistent with sound ratemaking principles. We disagree with the CAC. We have recently found movement towards more straight fixed variable rate design to be appropriate and consistent with traditional cost causation principles. *Indianapolis Power & Light Co.,* Cause Nos. 44576 and 44602, 2016 WL 1118795 (IURC March 16, 2016) (as corrected by *Indianapolis Power & Light Co.,* Cause Nos. 44576 and 44602, 2016 WL 1179961 (IURC March 23, 2016)).

Upon consideration of the evidence, the Commission finds that the increase in the monthly customer charge from \$11.00 to \$14.00 for residential service under Rate 111 is reasonable and is approved.

The Settling Parties also agreed with the provisions of NIPSCO's Proposed Tariff, subject to the following modifications to:

- Rate 115 – Multiple Family Housing Service. The Settling Parties agree NIPSCO will implement a Customer Charge of \$17.50 per month along with a Distribution Charge based on consumption for residential customers taking service under this rate. For Step Three rates, the overall impact on the Multiple Family Housing Service class will result in a \$59,064 increase in revenue, which equals a 2.72% increase to the class.

- Rate 128 – Large Firm Transportation and Balancing Service will be for firm service, and it will be a three-part rate consisting of a customer/meter charge of \$1,000.00, a demand charge that targets to recover 10% of the fixed costs allocated to the rate class, and a volumetric charge. The Settling Parties agree that Rate 128 will be divided into two sub-rates reflecting distinct cost allocation between the sub-rates but with no impact on any rate classes outside of Rate 128. The sub-rates shall be designated Rate 128 HP (designating those Rate 128 customers served exclusively from facilities at or above 60 PSIG) and Rate 128 DP (all other Rate 128 customers). The demand charges for Rate 128 high pressure and distribution pressure sub-rates will be subject to an annual update to reflect recovery of

$2,549,903 for 128 HP and $805,239 for 128 DP from the total rate class based upon the class demand determinants from the preceding winter season (December, January, and February). The Settling Parties agree that the update process for demand charges is a mechanism for compromise and should not be treated in future proceedings as an endorsement as to methodology.

- Rate 138 – General Transportation and Balancing Service will also be a three-part rate consisting of a customer/meter charge of $750.00, a demand charge that targets to recover 10% of the fixed costs allocated to the rate class, and a volumetric charge. For Step Three rates, the overall impact on the Rate 138 class is a $1,325,439 increase in revenue, which equals a 38.93% increase to the class. The demand charge for Rate 138 will be subject to an annual update to reflect recovery of $250,161 from the rate class based upon the class demand determinants from the preceding winter season (December, January, and February). The Settling Parties agree that the update process for demand charges is a mechanism for compromise and should not be treated in future proceedings as an endorsement as to methodology.

- Excluding the fixed monthly charges specifically discussed above, the Settling Parties agree that NIPSCO should be authorized to increase all fixed monthly charges as NIPSCO proposed in this proceeding by no more than 25%. (This includes NIPSCO being authorized to increase the bank capacity charge.)

- The Settling Parties agreed to proposed language changes to NIPSCO's Schedules of Rates and Riders Applicable to Gas Service (including changes to Rates 128 and 138 and Riders 131 and 189, which were subject to revision and clarification following negotiations). The agreed upon language is attached to NIPSCO Witness Westerhausen's Settlement Testimony as Attachment 16-S-A, including the illustrative rates for Step One, Step Two, and Step Three in Attachment 16-S-D. With regard to Rider 189, NIPSCO agrees to the following: (i) no existing customer will be required to receive service under Rider 189 based on current usage patterns; (ii) existing balancing services will not be reduced for purposes of determining undue burden; and (iii) unless a material change in circumstance significantly increases intraday swings resulting in substantial penalties on a persistent basis over an extended period of time, an existing customer will not be required to take service under Rider 189.

- The Settling Parties agreed to proposed changes to NIPSCO's General Rules and Regulations Applicable to Gas Service (including changes to Rule 13, which were subject to revision and clarification following negotiations.) The agreed upon language is attached to NIPSCO Witness Westerhausen's Settlement Testimony as Attachment 16-S-A.

Having considered the evidence supporting the proposed revisions incorporated into the Settlement Tariff, the Commission approves the Settlement Tariff as attached to NIPSCO Witness Westerhausen's Settlement Testimony as Attachment 16-S-A.

(9) TDSIC Revenue Allocation Factors. The Settling Parties agree that Rider 188 – Transmission, Distribution, and Storage System Improvement Charge shall utilize the allocators set forth in Joint Exhibit E. The Settling Parties agree that in the event NIPSCO seeks to modify the allocation percentages to reflect significant migrations of customers amongst the various rate classes in order to prevent any unintended consequences of the migration of customers and to reasonably allocate their estimated share of the revenue requirement, NIPSCO agrees to identify such modifications in pre-filed testimony and provide supporting testimony. And the Settling Parties reserve the right to conduct discovery and raise issues with any proposed modification. That provision was not opposed by any party in this case. Upon consideration of the evidence and finding that the proposed allocators in Joint Exhibit E are reasonable, the Commission approves the customer class revenue allocation factors shown in Joint Exhibit E.

(10) FMCA Revenue Allocation Factors. The Settling Parties agreed that Rider 190 – FMCA (currently pending approval in Cause No. 45007) shall utilize the allocators set forth in Joint Exhibit F. The Settling Parties agreed that in the event NIPSCO seeks to modify the allocation percentages to reflect significant migrations of customers amongst the various rate classes in order to prevent any unintended consequences of the migration of customers and to reasonably allocate their estimated share of the revenue requirement, NIPSCO agrees to identify such modifications in pre-filed testimony and provide supporting testimony; the Settling Parties reserve the right to conduct discovery and raise issues with any proposed modification. That provision was not opposed by any party in this case. Based upon our consideration of the evidence, including the Settlement provisions agreed to by the Settling Parties, we find that the proposed FMCA Revenue Allocation Factors are reasonable. Therefore, the Commission approves the customer class revenue allocation factors shown in Joint Exhibit F.

19. Settlement Not Precedent. The parties agree that the Settlement should not be used as precedent in any other proceeding or for any other purpose, except to the extent necessary to implement or enforce its terms. Consequently, with regard to future citation of the Settlement, we find that our approval herein should be construed in a manner consistent with our finding in *Richmond Power & Light,* Cause No. 40434, 1997 WL 34880849, at 7 (IURC Mar. 19, 1997).

20. Conclusion Regarding Settlement. For the foregoing reasons, we find and conclude that the Settlement presents a reasonable, balanced, and comprehensive resolution of the issues in this Cause. Therefore, the Commission further finds and concludes that the Settlement is reasonable, supported by substantial evidence, and in the public interest. Accordingly, the Settlement is approved.

21. Confidential Information. On September 27, 2017, and on March 28, 2017, NIPSCO filed its First and Second Motions for Protection and Nondisclosure of Confidential and Proprietary Information. The motions were supported by affidavits intending to show documents to be submitted to the Commission were trade secret information within the scope of Ind. Code §§ 5-14-3-4(a)(4) and (9) and Ind. Code § 24-2-3-2. On October 25, 2017, and on April 16, 2018, the Presiding Officers issued docket entries finding the information supported by NIPSCO's First and Second Motions to be confidential on a preliminary basis. After review of the documents submitted in accordance with the October 25, 2017 and April 16, 2018 docket entries, we find all such information qualifies as confidential trade secret information pursuant to Ind. Code §§ 5-14-3-4 and 24-2-3-2. Therefore, the Commission affirms the preliminary rulings and finds this information is excepted from the public access requirements contained in Ind. Code ch. 5-14-3 and Ind. Code § 8-1-2-29 and should be held confidential and protected from public disclosure by the Commission.

IT IS THEREFORE ORDERED BY THE INDIANA UTILITY REGULATORY COMMISSION that:

1. The Stipulation and Settlement Agreement between Northern Indiana Public Service Company LLC, the Indiana Office of Utility Consumer Counselor, the NIPSCO Industrial Group, the NIPSCO Supplier Group, Steel Dynamics, Inc., EDF Energy Services, LLC, and Direct Energy Business Marketing, LLC and its affiliate Direct Energy Services, LLC, filed in this Cause on April 20, 2018, and attached hereto is approved.

2. NIPSCO is authorized to implement the authorized rate increase in three steps as set forth in Ordering Paragraphs 3, 4, and 5 below. Prior to implementing the rates authorized in this Order, NIPSCO shall file the tariff and applicable rate schedules under this Cause with the Commission, and such rates shall be effective subject to the Energy Division's review and agreement with the amounts reflected.

3. For Step One, NIPSCO shall file new schedules of rates and charges based on the agreed revenue requirement as adjusted to reflect the original cost of NIPSCO's net utility plant in-service, actual capital structure, and associated depreciation expense as of June 30, 2018. Step One rates will become effective no earlier than October 1, 2018. Joint Exhibit A to the Stipulation and Settlement Agreement represents the schedules supporting the calculation of NIPSCO's revenue requirement based on the 12-month period ending June 30, 2018.

4. For Step Two, NIPSCO shall file new schedules of rates and charges based on the agreed revenue requirement as of December 31, 2018, as adjusted, if necessary, to reflect the lesser of the following: (i) NIPSCO's forecasted test-year-end rate base as updated in its rebuttal evidence ($1,520,209,700), or (ii) NIPSCO's certified test-year-end net plant in-service as of December 31, 2018. Step Two rates will go into effect for usage beginning on the date that NIPSCO certifies its test-year-end net plant in-service, or January 1, 2019, whichever is later. Joint Exhibit B to the Stipulation and Settlement Agreement represents the schedules supporting the calculation of NIPSCO's revenue requirement based on the 12-month period ending December 31, 2018. The OUCC and intervening parties will have 60 days from the date of certification to state any objections to NIPSCO's certified test-year-end net plant in-service. If there are objections, a hearing will be held to determine NIPSCO's actual test-year-end net plant in-service, and rates will be trued-up (with carrying charges) retroactive to the date that NIPSCO's Step Two rates became effective.

5. For Step Three, NIPSCO shall file new schedules of rates and charges to pass back unprotected excess ADIT to customers beginning January 1, 2020, over a 12-year amortization period. Step Three rates will become effective on January 1, 2020, based on a compliance filing to be made by NIPSCO prior to that date. Joint Exhibit C to the Stipulation and Settlement Agreement represents the schedules supporting the calculation of NIPSCO's revenue requirement based on the pass back of unprotected excess ADIT.

6. All schedules of rates and charges submitted under Ordering Paragraph 3, 4, and 5 shall be developed according to the agreed on rate design as filed with the Stipulation and Settlement Agreement and otherwise in the manner described by the terms of the Stipulation and Settlement Agreement, including the agreed on allocation among customer classes.

7. The proposed Gas Service Tariff, Original Volume No. 8 as filed on April 20, 2018, is approved consistent with the Stipulation and Settlement Agreement and this Order inclusive of the associated General Rules and Regulations and Standard Contract.

8. NIPSCO's proposed depreciation rates are approved consistent with the Stipulation and Settlement Agreement and this Order.

9. The information submitted under seal in this Cause by NIPSCO and the Industrial Group (Nick Phillips, Jr.) pursuant to motions for protective orders filed by NIPSCO on September 27, 2017, and on March 28, 2018, are determined to be confidential trade secret information as defined in Ind. Code § 24-2-3-2 and exempt from public access and disclosure pursuant to Ind. Code §§ 8-1-2-29 and 5-14-3-4.

10. This Order shall be effective on and after the date of its approval.

HUSTON, KREVDA, OBER AND ZIEGNER CONCUR; FREEMAN ABSENT:

APPROVED: SEP 19 2018

I hereby certify that the above is a true and correct copy of the Order as approved.

Mary M. Becerra

Mary M. Becerra
Secretary of the Commission

FILED
April 20, 2018
INDIANA UTILITY
REGULATORY COMMISSION

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY FOR (1) AUTHORITY TO MODIFY ITS RATES AND CHARGES FOR GAS UTILITY SERVICE THROUGH A PHASE IN OF RATES; (2) MODIFICATION OF THE SETTLEMENT AGREEMENTS APPROVED IN CAUSE NO. 43894; (3) APPROVAL OF NEW SCHEDULES OF RATES AND CHARGES, GENERAL RULES AND REGULATIONS, AND RIDERS; (4) APPROVAL OF REVISED DEPRECIATION RATES APPLICABLE TO ITS GAS PLANT IN SERVICE; (5) APPROVAL OF NECESSARY AND APPROPRIATE ACCOUNTING RELIEF; AND (6) AUTHORITY TO IMPLEMENT TEMPORARY RATES CONSISTENT WITH THE PROVISIONS OF IND. CODE CH. 8-1-2-42.7.	)	**CAUSE NO. 44988**

SUBMISSION OF STIPULATION AND SETTLEMENT AGREEMENT

Northern Indiana Public Service Company LLC, by counsel, on behalf of itself and the Indiana Office of Utility Consumer Counselor ("OUCC"), the NIPSCO Industrial Group, the NIPSCO Gas Supplier Group, Steel Dynamics, Inc., EDF Energy Services, LLC, and Direct Energy Business Marketing, LLC and its affiliate Direct Energy Services, LLC (collectively, the "Settling Parties"), respectfully submits the attached Stipulation and Settlement Agreement ("Settlement Agreement").

Respectfully submitted on behalf of Settling Parties:

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CERTIFICATE OF SERVICE

The undersigned certifies that a copy of the foregoing was served upon the following via electronic email this 20TH day of April, 2018 to:

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STIPULATION AND SETTLEMENT AGREEMENT

This Stipulation and Settlement Agreement is entered into as of the 20th day of April, 2018, by and between Northern Indiana Public Service Company LLC ("NIPSCO" or "Company), the Indiana Office of Utility Consumer Counselor ("OUCC"), the NIPSCO Industrial Group ("Industrial Group"),[1] the NIPSCO Gas Supplier Group ("GSG"),[2] Steel Dynamics, Inc. ("SDI"), EDF Energy Services, LLC ("EDF"), and Direct Energy Business Marketing, LLC and its affiliate Direct Energy Services, LLC (together "Direct Energy"), (collectively, the "Settling Parties") (the "Agreement"), who stipulate and agree for purposes of settling the issues in Cause Nos. 44988 and 45007 that the terms and conditions set forth below represent a fair and reasonable resolution of all issues subject to incorporation into Final Orders of the Indiana Utility Regulatory Commission ("Commission") without any modification or condition that is not acceptable to the Settling Parties.

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[1] The companies that comprise the NIPSCO Industrial Group in Cause No. 44988 are Arcelor Mittal USA, Arconic, Inc., BP Products North America, Inc., Cargill, Inc., Fiat Chrysler Automobiles, General Motors LLC, NLMK Indiana, Praxair, Inc., Rea Magnet Wire Company, Inc., United States Steel Corporation, and USG Corporation.

[2] The entities that comprise the NIPSCO Gas Supplier Group in Cause No. 44988 are CenterPoint Energy, Inc., and the Retail Energy Supply Association.

A. Background.

1. NIPSCO's Current Rates and Charges.

a. Base Rates and Charges. The Commission's November 4, 2010 Order in Cause No. 43894 approved a Stipulation and Settlement Agreement between NIPSCO, the OUCC, the Industrial Group,[3] NIPSCO Marketer Group ("Marketer Group"),[4] and Citizens Action Coalition of Indiana, Inc. ("CAC") (the "2010 Rate Case Settlement") establishing NIPSCO's current basic rates and charges and depreciation rates ("2010 Rate Case Order").

The Commission's May 31, 2011 Order in Consolidated Cause Nos. 43941, 43942 and 43943 approved a Stipulation and Settlement Agreement between NIPSCO, the OUCC and the Marketer Group whereby the former Kokomo Gas & Fuel Company and Northern Indiana Fuel & Light Company Inc. were merged into NIPSCO, and the rates approved in the 2010 Rate Case Order were made applicable to customers across the footprint of the consolidated company (the "Merger Order"). The Merger Order also approved an addition to the authorized net operating income of the consolidated company resulting in a total authorized net operating income of $44,443,966.

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[3] In Cause No. 43894, Industrial Group consisted of Arcelor Mittal USA, Beta Steel Corporation, Praxair, Inc. and United States Steel Corporation.

[4] In Cause No. 43894, the Marketer Group consisted of Border Energy, Vectren Retail, LLC and Nordic Energy Services, LLC.

The Commission's August 28, 2013 Order in Cause No. 43894 approved a Stipulation and Settlement Agreement between the parties in Cause No. 43894 modifying the 2010 Rate Case Settlement (the "2013 Extension Agreement") (the "Extension Order"). The Extension Order approved the parties' agreement that the 2013 Extension Agreement shall be subject to review no earlier than May 1, 2017, and that NIPSCO's basic rates and charges should remain in effect through November 4, 2020, or further order of the Commission.

b. <u>NIPSCO's Alternative Regulatory Plan.</u> NIPSCO has operated under the terms of an approved alternative regulatory plan ("ARP") under Ind. Code § 8-1-2.5 since the Commission's Order dated October 8, 1997 in Cause No. 40342. The ARP was renewed and modified in Cause No. 41338, consolidated Cause Nos. 42800 and 42884, and Cause No. 43837. The ARP was most recently extended and modified and became a permanent part of NIPSCO's tariff on March 15, 2012 in Cause No. 44081 (the "Current Gas ARP").

c. <u>Gas Cost Adjustment ("GCA") Proceedings.</u> NIPSCO files a quarterly Gas Cost Adjustment ("GCA") proceeding in Cause No. 43629-GCA-XXX to adjust its rates to account for fluctuation in its gas costs.

d. <u>NIPSCO's Gas Tracking Mechanisms.</u>

Pursuant to the Commission's December 28, 2011 Order in Cause No. 44001, NIPSCO files an annual proceeding in Cause No. 44001-GDSM-XX for recovery of program costs associated with approved demand side management and energy efficiency programs through its Rider 472 – Gas Demand Side Management ("GDSM") Rider and Appendix C – GDSM Factors.[5]

Pursuant to the Commission's 2010 Rate Case Order, NIPSCO files an annual update to Appendix E – Unaccounted for Gas Percentage for recovery through NIPSCO's quarterly GCA proceeding in accordance with Ind. Code § 8-1-2-42(g) in Cause No. 43629-GCA-XXX.

Pursuant to the Commission's January 28, 2015 Order in Cause No. 44403-TDSIC-1, NIPSCO files a semi-annual proceeding in Cause No. 44403-TDSIC-XX to recover 80% of approved capital expenditures and TDSIC costs incurred in connection with NIPSCO's eligible transmission, distribution, and storage system improvements ("TDSIC Projects") through its Rider 488 – Adjustment of Charges for Transmission, Distribution and Storage System Improvement Charge and Appendix F – Transmission, Distribution and Storage System Improvement Charge Adjustment Factor. Pursuant to the provisions of the

[5] The Commission's May 9, 2007 Order in Cause No. 43051 initially approved Rider 472-Energy Efficiency Rider and Appendix C – Gas Efficiency Factor. The Commission's December 28, 2011 Order in Cause No. 44001 approved NIPSCO's request to change to a semi-annual reconciliation. The Commission's February 22, 2017 Order in Cause No. 44001-GDSM-10 approved NIPSCO's request to change from a semi-annual to annual filing.

TDSIC Statute,[6] 20% of approved TDSIC costs have been deferred for recovery in NIPSCO's next general rate case ("TDSIC deferred balance").

2. Pending NIPSCO Gas Proposals.

a. Cause No. 44988. On September 27, 2017, NIPSCO filed with the Commission its Verified Petition to modify its rates and charges for gas utility service, for approval of new schedules of rates and charges applicable thereto, and for approval of certain other requests (the "2017 Gas Rate Case"). NIPSCO also filed its prepared testimony and exhibits constituting its case-in-chief on that date together with a proposed procedural schedule. On November 9, 2017 the Commission issued a docket entry establishing various dates and procedural requirements governing the proceeding. The 2017 Gas Rate Case made use of a forward looking test year ending December 31, 2018 pursuant to the provisions of Ind. Code § 8-1-2-42.7(d)(1).

b. Cause No. 45007. On November 8, 2017, NIPSCO filed its Verified Petition initiating a request for approval of a certificate of public convenience and necessity for a Pipeline Safety Compliance Plan to comply with certain federal pipeline safety performance standards and regulations pursuant to the provisions of Ind. Code ch. 8-1-8.4 and seeking associated ratemaking treatment for costs associated with the Pipeline Safety Compliance Plan (the "Gas FMCA Proceeding"). The proposed Pipeline

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6 Ind. Code ch. 8-1-39 (the "TDSIC Statute").

Safety Compliance Plan is made up of a portfolio of projects that together are intended to comply with a range of federally mandated requirements.

B. Settlement Terms.

1. Cause No 44988.

a. Predication of Settlement Rates. The Settling Parties agree that NIPSCO should be authorized to increase its basic rates and charges for natural gas utility service in three steps as described in this Agreement. The first change in rates will be based on the agreed revenue requirement as adjusted to reflect the original cost of NIPSCO's net utility plant in service, actual capital structure, and associated depreciation expense as of June 30, 2018 ("Step 1"). Step 1 rates will become effective on October 1, 2018.[7] Joint Exhibit A attached hereto represents the schedules supporting the calculation of NIPSCO's revenue requirement based on the 12-month period ending June 30, 2018.

The second change in rates will be based on the agreed revenue requirement as of December 31, 2018, as adjusted, if necessary, to reflect the lesser of (a) NIPSCO's forecasted test-year-end rate base as updated in its rebuttal evidence ($1,520,209,700), or (b) NIPSCO's certified test-year-end net plant in service as of December 31, 2018 ("Step 2"). Step 2 rates will go into effect for usage beginning on the date that NIPSCO certifies its test year-end net plant in service, or January 1, 2019, whichever is later. Joint Exhibit

7 Assuming a Final Order is issued in this Cause on or about September 24, 2018.

B attached hereto represents the schedules supporting the calculation of NIPSCO's revenue requirement based on the 12-month period ending December 31, 2018.

The third change in rates will be to pass back unprotected excess Accumulated Deferred Income Taxes ("ADIT") to customers beginning January 1, 2020 over a twelve year amortization period ("Step 3"). Step 3 rates will become effective on January 1, 2020 based on a compliance filing to be made by NIPSCO prior to that date. Joint Exhibit C attached hereto represents the schedules supporting the calculation of NIPSCO's revenue requirement based on the pass back of unprotected excess ADIT.

b. Revenue Requirement and Net Operating Income.

(1) Revenue Requirement. For purposes of Step 3 rates, the Settling Parties agree that NIPSCO's Revenue Requirement will be no more than $409,763,474, which represents gross margin and is net of all of the Company's gas costs, which will continue to be separately recovered through the Company's GCA Mechanism. The Settling Parties agree that NIPSCO's base rates will be designed to produce a Revenue Requirement no more than $726,671,093, less $6,855,023 of Other Revenues. This Revenue Requirement is a decrease of $48,958,762from the amount originally requested by the Company.

(2) Net Operating Income. The Settling Parties agree that NIPSCO's Revenue Requirement in Paragraph B.1.b.(1) results in a proposed authorized net operating income ("NOI") of $98,813,631.

c. Original Cost Rate Base, Capital Structure and Fair Return.

(1) Original Cost Rate Base. NIPSCO has agreed that its weighted cost of capital times its original cost rate base yields a fair return for purposes of this case. Based upon this agreement, the Settling Parties agree that NIPSCO should be authorized a fair return of no more than $98,813,631 yielding an overall return for earnings test purposes of 6.50%, based upon: (a) an original cost rate base of $1,520,209,700, inclusive of gas in underground storage, materials and supplies, and TDSIC Regulatory Asset as proposed in NIPSCO's case-in-chief; (b) NIPSCO's capital structure; and (c) an authorized return on equity ("ROE") of 9.85%.

(2) Capital Structure and Fair Return. Based on the following capital structure, the 9.85% ROE and cost of debt/zero cost capital as agreed, the overall weighted average cost of capital is computed as follows:

	% of Total	Cost %	WACC %
Common Equity	46.88%	9.85%	4.62%
Long-Term Debt	36.80%	4.94%	1.82%
Customer Deposits	1.22%	4.91%	0.06%
Deferred Income Taxes	21.10%	0.00%	0.00%
Prepaid Pension Asset	-7.43%	0.00%	0.00%
Post-Retirement Liability	1.39%	0.00%	0.00%
Post-1970 ITC	0.04%	7.69%	0.00%
Totals	**100.0%**		**6.50%**

d. Depreciation and Amortization Expense.

(1) Depreciation Expense. The Settling Parties stipulate that the depreciation accrual rates recommended by NIPSCO Witness John Spanos and presented in this proceeding (the "Depreciation Study") should be approved and used in the determination of net plant in service values for the calculation of Step 1, Step 2 and Step 3 rates. NIPSCO continues to use the depreciation rates applicable to its common plant as approved by the Commission in NIPSCO's last electric general rate proceeding in Cause No. 44688.

(2) Amortization Expense. The Settling Parties agree to the amortization of regulatory assets for rate case expense and the TDSIC deferred balance over a period of seven (7) years. For rate case expense, the Settling Parties stipulate that annual amortization expense shall reflect a reduction of $140,000 from that proposed in NIPSCO's case-in-chief. If not

already addressed by an intervening base rate case order, after the completion of the seven (7) year period, NIPSCO agrees to make a tariff filing that will reflect the reduction in amortization expense as a result of the end of rate case expense and TDSIC deferred balance amortization.

e. Tax Cuts and Jobs Act of 2017. The Settling Parties agree to the treatment of excess income taxes occasioned by the Tax Cuts and Jobs Act of 2017 ("Tax Act") as follows: Cause No. 45032, "Phase 1." The Settling Parties agree that NIPSCO will revise its base rates and charges consistent with the revised tariffs that NIPSCO filed on March 26, 2018, and NIPSCO will not request a subdocket in Phase 1 of Cause No. 45032.

(2) Cause No. 45032, "Phase 2." The Settling Parties agree to the treatment of excess income taxes and excess deferred income tax balances occasioned by the Tax Act as follows:

(a) NIPSCO will return excess income tax revenue recovered through its base rates and any applicable charges between January 1, 2018 and April 30, 2018 (assuming approval of its March 26, 2018 tariffs on or around April 25, 2018) currently reflected as a regulatory liability in accordance with the Commission's January 3, 2018 Order initiating Cause No. 45032, and identified as "Phase 1" of that proceeding in its February 16, 2018 Order in that cause over a six (6) month period beginning January 1, 2019 through its approved TDSIC mechanism in Cause No. 44403 TDSIC-9 to be filed on or before September 1, 2018. Other than the excess income tax collected through the TDSIC, which should be allocated based on the allocation methodology used in that tracker, the allocation of the remaining excess income tax amounts between rate classes will be addressed in Cause No. 44403 TDSIC-9 and is not governed by this Stipulation and Settlement Agreement.

(b) As of December 31, 2017, NIPSCO recorded protected excess Accumulated Deferred Income Taxes ("ADIT") of $24,169,649. NIPSCO will continue to utilize the average rate assumption method ("ARAM") to pass back to customers. NIPSCO shall be authorized to record the differences between ARAM and the amortization passed back through base rates (estimated using a 45.8 year amortization period) as a regulatory asset or liability for treatment in NIPSCO's next base rate case.

(c) As of December 31, 2017, NIPSCO recorded unprotected excess ADIT of $73,743,924. NIPSCO will pass it back to customers beginning January 1, 2020 over a twelve year amortization period. NIPSCO agrees to make a compliance filing in Cause No. 44988 in late 2019 to show the calculation of the reduced rates to be effective January, 2020.

(d) These provisions address all issues in Phase 2 of Cause No. 45032 and NIPSCO Gas shall be dismissed from the Phase 2 proceeding.

f. Regulatory Treatment of Current Gas ARP Margins. The Settling Parties agree that the regulatory treatment of NIPSCO's margins associated with NIPSCO's Current Gas ARP programs shall remain unchanged. Those margins shall be included in the GCA NOI earnings test pursuant to Ind. Code §§ 8-1-2-42(g)(3)(C) and 8-1-2-42.3 except for: (a) NIPSCO's Gas Cost Incentive Mechanism ("GCIM") (Rule 15), Capacity Release (Rule 16), and Optional Storage Service Rider (Rider 142A), which shall be treated as below-the-line but shall continue to be shared with customers through the GCA as provided in the Current Gas ARP; (b) NIPSCO's DependaBill program (Rate 151); and (c) Price Protection Service ("PPS") (Rider 181).

NIPSCO agrees to maintain competitive neutrality, to proactively support customer choice, to enhance transparency, and to ensure fair cost allocation in regard to its products and service in order to avoid: (a) subsidization of its competitive products, specifically PPS and DependaBill, and the operational and overhead costs associated with those products; and (b) optimization of assets in a manner inconsistent with or broader than otherwise currently permitted by the Stipulation approved by the Commission in Cause No. 43837. The code of conduct consistent with those principles and objectives approved by the Commission in the Merger Order will continue in effect.

g. Cost Allocation and Rate Design. The Settling Parties agree that rates should be designed in order to allocate the revenue requirement to and among NIPSCO's customer classes in a fair and reasonable manner and consistent with cost causation principles. For settlement purposes, the Settling Parties agree that NIPSCO should design its rates using the structure of its proposed 100 Series tariffs in the manner described below.

(1) Residential Service. The Settling Parties agree NIPSCO will implement a Customer Charge of $14.00 per month along with a Distribution Charge based on consumption for Residential Customers taking service under Rate 111 – Residential Service. For Step 3 rates, the

overall impact on the Residential Service class will result in a 68,485,505 increase in revenue, which equals a 36.21% increase to the class.[8]

(2) Multiple Family Housing Service. The Settling Parties agree NIPSCO will implement a Customer Charge of $17.50 per month along with a Distribution Charge based on consumption for residential customers taking service under Rate 115 – Multiple Family Housing Service. For Step 3 rates, the overall impact on the Multiple Family Housing Service class will result in a $59,064 increase in revenue, which equals a 2.72% increase to the class.

(3) General Service - Small. The Settling Parties agree NIPSCO will implement a Customer Charge of $53.00 per month along with a Distribution Charge based on consumption for small Non-Residential Customers. For Step 3 rates, the overall impact on the General Service Small class will result in a $23,580,422 increase in revenue, which equals a 37.70% increase to the class.

[8] All references to increases in revenue dollars and percentages reflect an assumption that the revised rates pursuant to the Phase I filing in Cause No. 45032 as referenced in B.1.e.(1) above are approved and implemented as filed.

(4) General Service - Large. The Settling Parties agree NIPSCO will implement a Customer Charge of $400.00 per month along with a Distribution Charge based on consumption for large Non-Residential Customers. For Step 3 rates, the overall impact on the General Service Large class will result in a $2,926,525 increase in revenue, which equals a 27.47% increase to the class.

Rate 128 – Large Firm Transportation and Balancing Service will be for a firm service, and will be a three-part rate consisting of a customer/meter charge of $1,000.00, a demand charge that targets to recover ten percent (10%) of the fixed costs allocated to the rate class, and a volumetric charge. For Step 3 rates, the overall impact on the Rate 128 class will be an $10,721,786 increase in revenue, which equals a 38.98% increase to the class. The Settling Parties agree that Rate 128 will be divided into two sub-rates reflecting distinct cost allocation between the sub-rates but with no impact on any rate classes outside of Rate 128. The sub-rates shall be designated Rate 128 HP (designating those Rate 128 customers served exclusively from facilities at or above 60 psig) and Rate 128 DP (all other Rate 128 customers). The demand charges for Rate 128 high pressure and distribution pressure sub-rates will be subject to an annual update to reflect recovery of $2,549,903 for 128 HP and $805,239 for 128 DP from the total rate class based upon the class demand determinants from the preceding winter season (December, January, and February). The Settling Parties agree that the update process for demand charges is a mechanism for compromise and should not be treated in future proceedings as an endorsement as to methodology.

Rate 138 – General Transportation and Balancing Service, will also be a three-part rate consisting of a customer/meter charge of $750.00, a demand charge that targets to recover ten percent (10%) of the fixed costs allocated to the rate class, and a volumetric charge. For Step 3 rates, the overall impact on the Rate 138 class is a $1,325,439 increase in revenue, which equals a 38.93% increase to the class. The demand charge for Rate 138 will be subject to an annual update to reflect recovery of $250,161 from the rate class based upon the class demand determinants from the preceding winter season (December, January, and February). The Settling Parties agree that the update process for demand charges is a mechanism for compromise and should not be treated in future proceedings as an endorsement as to methodology.

(5) <u>All other fixed monthly charges.</u> The Settling Parties agree that NIPSCO should be authorized to increase all fixed monthly charges not

specifically discussed above as to which NIPSCO had proposed an increase in this proceeding (including, but not limited to, the bank capacity charge) by no more than 25%.

(6) Schedules of Rates and Riders. The Settling Parties agree to the proposed language changes to NIPSCO's Schedules of Rates and Riders Applicable to Gas Service (including changes to Rates 128 and 138 and Riders 131 and 189, which were subject to revision and clarification following negotiations) as attached to NIPSCO Witness Westerhausen's Settlement Testimony as Attachment 16-S-A, including the illustrative rates for Step 1, Step 2, and Step 3 in Attachment 16-S-D. With regard to Rider 189, NIPSCO agrees that (1) no existing customer will be required to receive service under Rider 189 based on current usage patterns, (2) existing balancing services will not be reduced for purposes of determining undue burden, and (3) unless a material change in circumstance significantly increases intraday swings resulting in substantial penalties on a persistent basis over an extended period of time an existing customer will not be required to take service under Rider 189.

(7) General Rules and Regulations. The Settling Parties agree to the proposed changes to NIPSCO's General Rules and Regulations

Applicable to Gas service (including changes to Rule 13, which were subject to revision and clarification following negotiations) as attached to NIPSCO Witness Westerhausen's Settlement Testimony as Attachment 16-S-A.

(8) The Settling Parties agree that the cost allocation herein results in fair and reasonable rates and charges as reflected in Joint Exhibit D. Regarding the TDSIC Tracker, this mechanism shall utilize the allocators set forth in Joint Exhibit E. Regarding the FMCA Tracker, and solely for purposes of Cause No. 45007, this mechanism shall utilize the allocators set forth in Joint Exhibit F. In the event NIPSCO seeks to modify the allocation percentages to reflect significant migrations of customers amongst the various rate classes in order to prevent any unintended consequences of the migration of customers and to reasonably allocate their estimated share of the revenue requirement, NIPSCO agrees to identify such modifications in pre-filed testimony and provide supporting testimony, and the Settling Parties reserve the right to conduct discovery and raise issues with any proposed modification.

h. Certification of Rates

(1) Step 1 Rates

(a) NIPSCO will certify its net plant in service as of June 30, 2018 and calculate the resulting Step 1 rates using its actual capital structure as of that date.

(b) Assuming a Final Order date of September 24, 2018, Step 1 rates will become effective on October 1, 2018.

(2) <u>Step 2 Rates</u>

(a) NIPSCO will certify its net plant in service at test-year-end (December 31, 2018) and calculate the resulting Step 2 rates using its actual capital structure as of that date, subject to the provisions of Paragraph B.1.a. above.

(b) Step 2 rates will go into effect for usage on and after the date that NIPSCO certifies its test year-end net plant in service, or January 1, 2019, whichever is later.

(c) The OUCC and intervening parties will have 60 days from the date of certification to state any objections to NIPSCO's certified test-year-end net plant in service.

(d) If there are objections, a hearing will be held to determine NIPSCO's actual test-year-end net plant in service, and rates will be trued-up (with carrying charges) retroactive to the date that NIPSCO's Step 2 rates became effective pursuant to subparagraph (b) above.

(e) For purposes of this section, "certify" means NIPSCO has determined that it has completed the amount of net plant indicated in its certification and the corresponding net plant additions have been placed in service and are used and useful in providing utility service as of the date of certification. NIPSCO will serve all Settling Parties with its certification.

2. Cause No. 45007

a. Predication of Settlement. The Settling Parties acknowledge that neither the OUCC nor the Industrial Group have filed their respective cases-in-chief or cross-answering testimony, nor has NIPSCO filed its rebuttal case in Cause No. 45007. Therefore, this settlement is predicated on provision being made for the filing of the remainder of the parties' cases-in-chief, cross-answering testimony, and rebuttal case in the event the Commission modifies this Agreement or imposes further conditions unacceptable to any of the Settling Parties. In such event, the Settling Parties will cooperate in order to develop a schedule under which the OUCC and Industrial Group would file their respective cases-in-chief within two weeks following the Commission's issuance of such an Order, and NIPSCO would file its rebuttal within a reasonable time thereafter.

b. Approval of Pipeline Safety Compliance Plan. The Settling Parties agree to the approval of a Certificate of Public Convenience and Necessity for a Pipeline Safety Compliance Plan ("Compliance Plan") pursuant to the provisions of Ind. Code ch. 8-1-8.4 consistent with the following stipulations:

(1) Projects Proposed in Cause No. 45007. The Compliance Plan proposed by NIPSCO included a portfolio of nineteen projects. The Settling Parties stipulate and agree that those proposed projects should be included as components of the Compliance Plan for which a certificate pursuant to Ind. Code Ch. 8-1-8.4 should be approved.

(2) Projects Originally Proposed in Cause No. 44988. The Settling Parties stipulate and agree that the following five projects proposed for inclusion in base rates in Cause No. 44988 should instead be included as components of the Compliance Plan in Cause No. 45007: (1) Transmission Risk Modeling, (2) Legacy Cross Bore Inspection, (3) Test Station Casings, (4) MAOP – Distribution, and (5) MAOP – Transmission. The Settling Parties stipulate and agree that those five proposed projects should be

included as components of the Compliance Plan for which a certificate pursuant to Ind. Code Ch. 8-1-8.4 should be approved.

(3) Resulting Compliance Plan. The Settling Parties stipulate and agree that a certificate pursuant to Ind. Code Ch. 8-1-8.4 should be approved by the Commission for the Compliance Plan consisting of the following projects:

Project ID	Description
PS1	TIMP Programmatic Improvements Project
PS2	Management of Change Project
PS3	Preventive and Mitigative Measures Project
PS4	Annual Plan Improvements Project
PS5	Enhanced Emergency Responder Outreach Program
PS6	DIMP Administration/Leak Data Verification Project
PS7	Service Card Enhancements Project
PS8	Fiberglass Riser Replacement Project
PS9	Legacy Cross Bore Remediation Project
PS10	Underground Storage Integrity Project
PS11	Farm Tap Remediation Project
PS12	ILI Project
PS13	Transmission Inspect & Mitigate Project
PS14	AC Mitigation Project
PS15	Transmission RCV Installation Project
PS16	Isolated Services Project
PS17	Emergency Valve Project
PS18	Casings Project
PS19	Distribution Inspect & Mitigate Project
PS20 (OM 2D)	Transmission Risk Modeling
PS21 (OM 2F)	Legacy Cross Bore Inspection
PS22 (OM 2R)	Test Station Casings
PS23 (OM 2H)	MAOP – Distribution
PS24 (OM 2I)	MAOP – Transmission

(4) Compliance with Federal Mandates. The Settling Parties stipulate and agree that the portfolio of projects comprising the Compliance Plan including those five projects originally proposed in Cause No. 44988 are a "compliance project" properly undertaken in furtherance of one or more "federally mandated requirements" as those terms are defined in Ind. Code §§ 8-1-8.4-2 and 8-1-8.4-5, respectively.

(5) Estimated Federally Mandated Costs. The Settling Parties stipulate and agree that costs associated with the Compliance Plan are "federally mandated costs" as that term is defined in Ind. Code § 8-1-8.4-4, and agree that the total amount of projected federally mandated costs associated with the Compliance Plan is $91,493,664 of capital costs (inclusive of direct, indirect and AFUDC) and $35,499,727 of operating and maintenance costs and that such projected federally mandated costs should be approved by the Commission pursuant to the provisions of Ind. Code § 8-1-8.4.7(b)(2). The revised Pipeline Safety Compliance Plan is attached hereto as Confidential Joint Exhibit G.

The Settling Parties agree that, in total, such costs together with associated depreciation, tax and financing costs constitute the "approved federally mandated costs" for purposes of Ind. Code § 8-1-8.4-7(c). NIPSCO may seek to recover increases in the baseline capital and O&M costs set forth in Confidential Joint Exhibit G only as set forth in Paragraph B.2.c.(4) of this Agreement.

(6) Public Convenience and Necessity. The Settling Parties stipulate and agree that the public convenience and necessity will be served by the proposed Compliance Plan.

c. Implementation of Federally Mandated Cost Adjustment. The Settling Parties agree that NIPSCO should be authorized to implement a gas Federally Mandated Cost Adjustment ("FMCA") tracking mechanism pursuant to the provisions of Ind. Code § 8-1-8.4-7(c) consistent with the following stipulations:

(1) Recovery of Federally Mandated Costs Associated with the Compliance Plan. The Settling Parties stipulate and agree that eighty percent (80%) of the approved federally mandated costs associated with the Compliance Plan shall be recovered by NIPSCO through a semi-annual retail rate adjustment mechanism that allows the timely recovery of the approved federally mandated costs. The Settling Parties agree that petitions initiating such semi-annual filings should bear the Cause No. 45007-FMCA-XX.

(2) Increase in Authorized Earnings. NIPSCO's authorized net operating income should be adjusted to reflect any approved earnings associated with the Compliance Plan for purposes of Ind. Code §§ 8-1-2-42(g)(3).

(3) Deferral of Federally Mandated Costs Associated with the Compliance Plan. The Settling Parties agree that twenty percent (20%) of the approved federally mandated costs in accordance with Ind. Code ch. 8-1-8.4, shall be deferred and recovered by NIPSCO as part of its next general rate case filed with the Commission.

(4) Treatment of Actual Costs that Exceed Projected Federally Mandated Cost of Projects within the Compliance Plan. The Settling Parties agree that, for each of the 24 projects listed in Confidential Joint Exhibit G, actual costs that exceed the projected federally mandated costs by project as set forth in Confidential Joint Exhibit G by up to fifteen percent (15%) may be recovered within the FMCA. For actual costs that exceed the specific amount listed in Confidential Joint Exhibit G by more than fifteen percent (15%) but less than twenty-five percent (25%) of the specified amount shall be deferred, along with the appropriate regulatory asset and/or accounting treatment for recovery in NIPSCO's next general rate

case filed with the Commission. Such deferred amounts shall include carrying charges accrued at NIPSCO's long-term cost of debt as of December 31, 2018. Consistent with Ind. Code §8-1-8.4-7(c)(3), actual costs that exceed the specific amounts listed in Confidential Joint Exhibit G by 25% or more will require specific justification by NIPSCO and specific approval by the Commission before being authorized in NIPSCO's next general rate case.

C. Procedural Aspects and Presentation of the Agreement.

1. The Settling Parties acknowledge that a significant motivation to enter into this Agreement is the expectation that, if the Commission finds this Agreement is reasonable and in the public interest, an order authorizing the increase in NIPSCO's rates and charges will be issued in Cause No. 44988. The Settling Parties have spent valuable time reviewing data and negotiating this Agreement in an effort to eliminate time consuming and costly litigation. NIPSCO requests that the Commission review the Agreement on an expedited basis and, if it finds the Agreement is reasonable and in the public interest, the Settling Parties request the Commission approve this Agreement without any material changes no later than September 24, 2018.

2. The Settling Parties agree to jointly present this Agreement to the Commission for its approval in Cause Nos. 44988 and 45007, and agree to assist and

cooperate in the preparation and presentation of supplemental testimony as necessary to provide an appropriate factual basis for such approval.

3. If the Agreement is not approved in its entirety by the Commission, the Settling Parties agree that the terms herein shall not be admissible in evidence or discussed by any party in a subsequent proceeding. Moreover, the concurrence of the Settling Parties with the terms of this Agreement is expressly predicated upon the Commission's approval of the Agreement in its entirety without any material modification or any material condition deemed unacceptable by any Party. If the Commission does not approve the Agreement in its entirety, the Agreement shall be null and void and deemed withdrawn, upon notice in writing by any Settling Party within fifteen (15) business days after the date of the Final Order that any modifications made by the Commission are unacceptable to it. In the event the Agreement is withdrawn, the Settling Parties will request that an Attorneys' Conference be convened to establish a procedural schedule for the continued litigation of this proceeding.

4. The Settling Parties agree that this Agreement and each term, condition, amount, methodology and exclusion contained herein reflects a fair, just and reasonable resolution and compromise for the purpose of settlement, and is agreed upon without prejudice to the ability of any party to propose a different term, condition, amount, methodology or exclusion in future proceedings. As set forth in the Order in *Re Petition*

of Richmond Power & Light, Cause No. 40434, p. 10, the Settling Parties agree and ask the Commission to incorporate as part of its Final Order that this Agreement, or the Order approving it, not be cited as precedent by any person or deemed an admission by any party in any other proceeding except as necessary to enforce its terms before the Commission, or any court of competent jurisdiction on these particular issues. This Agreement is solely the result of compromise in the settlement process. Each of the Settling Parties hereto has entered into this Agreement solely to avoid further disputes and litigation with the attendant inconvenience and expenses.

5. The Settling Parties stipulate that the evidence of record presented in Cause Nos. 44988 and 45007 constitutes substantial evidence sufficient to support this Agreement and provide an adequate evidentiary basis upon which the Commission can make any findings of fact and conclusions of law necessary for the approval of this Agreement, as filed. The Settling Parties agree to the admission into the evidentiary record of this Agreement, along with testimony supporting it without objection.

6. The issuance of a Final Order by the Commission approving this Agreement without any material modification or further condition shall terminate all proceedings in this Cause.

7. The undersigned represent and agree that they are fully authorized to execute this Agreement on behalf of their designated clients who will be bound thereby.

8. The Settling Parties shall not appeal the agreed Final Order or any subsequent Commission order as to any portion of such order that is specifically implementing, without modification, the provisions of this Agreement and the Settling Parties shall not support any appeal of the portion of such order by a person not a party to this Agreement. All Settling Parties shall support the Final Order if appealed by any party not a signatory to this Agreement.

9. The provisions of this Agreement shall be enforceable by any Settling Party before the Commission or in any court of competent jurisdiction.

10. The communications and discussions during the negotiations and conferences which produced this Agreement have been conducted on the explicit understanding that they are or relate to offers of settlement and shall therefore be privileged and confidential.

ACCEPTED AND AGREED this 20th day of April, 2018.

[SIGNATURE PAGES FOLLOW]

Northern Indiana Public Service Company LLC

Violet Sistovaris

Violet Sistovaris, President

Indiana Office of Utility Consumer Counselor

William Fine, Utility Consumer Counselor

NIPSCO Industrial Group

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NIPSCO Gas Supplier Group

Joseph P. Rompala
____

Steel Dynamics, Inc.

Direct Energy Business Marketing, LLC
and its affiliate Direct Energy Services, LLC

Nikki Shoultz
____

EDF ENERGY SERVICES, LLC

Nikki Shoultz

By: Nikki G. Shoultz,
Counsel for EDF Energy Services, LLC

Northern Indiana Public Service Company
Statement of Operating Income - Step 1
Actual, Pro forma and Proposed
For the Twelve Month Period Ending June 30, 2018

Line No.	Description	Actual	Pro forma Adjustments Increases (Decreases)	Attachment 3-B-S1 Reference[1]	Pro forma Results Based on Current Rates	Pro forma Adjustments Increases (Decreases)	Attachment 3-D-S1 Reference	Pro forma Results Based on Proposed Rates
	A	B	C	D	E	F	G	H
1	**Operating Revenue**							
2	Revenue (Actual / Pro Forma)	$ 586,736,247		*Rev Sch 1-S3, Col A*	$ 619,371,092	$ 86,525,127	PF - 1-S1	$ 705,896,219
3	Pro forma Adjustments December 31, 2016		25,084,387	*Rev Sch 1-S3, Col B*				
4	Budget Adjustments December 31, 2017		39,185,274	*Rev Sch 1-S3, Col D*				
5	Budget Adjustments December 31, 2018		(1,085,090)	*Rev Sch 1-S3, Col F*				
6	Rate Making Adjustments December 31, 2018		(30,549,726)	*Rev Sch 1-S3, Col H*				
7	Total Operating Revenue	$ 586,736,247	$ 32,634,845		$ 619,371,092	$ 86,525,127		$ 705,896,219
8	**Gas Costs (Trackable)**							
9	Gas Cost (Actual / Pro Forma)	$ 296,774,989		*COGS Sch 1, Col A*	$ 316,907,619	-		$ 316,907,619
10	Pro forma Adjustments December 31, 2016		20,718,747	*COGS Sch 1, Col B*				
11	Budget Adjustments December 31, 2017		17,960,293	*COGS Sch 1, Col D*				
12	Budget Adjustments December 31, 2018		(6,596,838)	*COGS Sch 1, Col F*				
13	Rate Making Adjustments December 31, 2018		(11,949,572)	*COGS Sch 1, Col H*				
14	Total Gas Costs	$ 296,774,989	$ 20,132,630		$ 316,907,619	$ -		$ 316,907,619
15	**Gross Margin**	$ 289,961,258	$ 12,502,215		$ 302,463,473	$ 86,525,127		$ 388,988,600
16	**Operations and Maintenance Expenses**							
17	Operations and Maintenance Expenses (Actual / Pro Forma)	$ 181,866,867		*O&M Sch 1-S3, Col A*	$ 192,612,338	$ 261,258	PF - 2-S1	$ 192,873,596
18	Pro forma Adjustments December 31, 2016		194,118	*O&M Sch 1-S3, Col B*				
19	Budget Adjustments December 31, 2017		13,703,290	*O&M Sch 1-S3, Col D*				
20	Budget Adjustments December 31, 2018		3,573,727	*O&M Sch 1-S3, Col F*				
21	Rate Making Adjustments December 31, 2018		(6,725,664)	*O&M Sch 1-S3, Col H*				
22	Total Operations and Maintenance Expense	$ 181,866,867	$ 10,745,471		$ 192,612,338	$ 261,258		$ 192,873,596
23	**Depreciation Expense**							
24	Depreciation Expense (Actual / Pro Forma)	$ 9,629,139		*Depr Sch 1-S1, Col A*	$ 59,898,325			$ 59,898,325
25	Pro forma Adjustments December 31, 2016		-	*Depr Sch 1-S1, Col B*				
26	Budget Adjustments December 31, 2017		1,473,118	*Depr Sch 1-S1, Col D*				
27	Budget Adjustments December 31, 2018		4,098,075	*Depr Sch 1-S1, Col F*				
28	Rate Making Adjustments June 30, 2018		44,697,993	*Depr Sch 1-S1, Col H*				
29	Total Depreciation Expense	$ 9,629,139	$ 50,269,186		$ 59,898,325	$ -		$ 59,898,325

Northern Indiana Public Service Company
Statement of Operating Income - Step 1
Actual, Pro forma and Proposed
For the Twelve Month Period Ending June 30, 2018

Line No.	Description	Actual	Pro forma Adjustments Increases (Decreases)	Attachment 3-B-S1 Reference[1]	Pro forma Results Based on Current Rates	Pro forma Adjustments Increases (Decreases)	Attachment 3-D-S1 Reference	Pro forma Results Based on Proposed Rates
	A	B	C	D	E	F	G	H
30	**Amortization Expense**							
31	Amortization Expense (Actual / Pro Forma)	$ 4,650,834		*AMTZ Sch 1-S1, Col A*	$ 7,913,043			$ 7,913,043
32	Pro forma Adjustments December 31, 2016		-	*AMTZ Sch 1-S1, Col B*				
33	Budget Adjustments December 31, 2017		546,330	*AMTZ Sch 1-S1, Col D*				
34	Budget Adjustments December 31, 2018		602,714	*AMTZ Sch 1-S1, Col F*				
35	Rate Making Adjustments June 30, 2018		2,113,165	*AMTZ Sch 1-S1, Col H*				
36	Total Amortization Expense	$ 4,650,834	$ 3,262,209		$ 7,913,043	$ -		$ 7,913,043
37	**Taxes**							
38	**Taxes Other than Income**							
39	Taxes Other than Income (Actual / Pro Forma)	$ 22,416,370		*OTX Sch 1-S3, Col A*	$ 26,963,350			$ 26,963,350
40	Pro forma Adjustments December 31, 2016		351,429	*OTX Sch 1-S3, Col B*				
41	Budget Adjustments December 31, 2017		2,714,626	*OTX Sch 1-S3, Col D*				
42	Budget Adjustments December 31, 2018		1,136,298	*OTX Sch 1-S3, Col F*		$ 1,211,352	PF - 3-S1	$ 1,211,352
43	Rate Making Adjustments December 31, 2018		344,627	*OTX Sch 1-S3, Col H*		$ 115,154	PF - 4-S1	$ 115,154
44	Total Taxes Other Than Income	$ 22,416,370	$ 4,546,980		$ 26,963,350	$ 1,326,506		$ 28,289,856
45	**Operating Income Before Income Taxes**	$ 71,398,048	$ (56,321,631)		15,076,417	$ 84,937,363		$ 100,013,780
46	**Income Taxes**							
47	Federal and State Taxes (Actual / Pro Forma)	$ 21,354,892	(23,200,450)	*Attachment 3-D-S1 ITX 1*	$ (1,845,558)	$ 21,835,224	PF - 5-S1	$ 19,989,666
48	Total Taxes	$ 43,771,262	(18,653,470)		$ 25,117,792	$ 23,161,730		$ 48,279,522
49	**Total Operating Expenses including Income Taxes**	$ 239,918,102	$ 45,623,396		$ 285,541,498	$ 23,422,988		$ 308,964,486
50	**Required Net Operating Income**	$ 50,043,156	$ (33,121,181)		$ 16,921,975	$ 63,102,140		$ 80,024,114

Footnote 1 - Unless otherwise noted

Northern Indiana Public Service Company
Calculation of Proposed Revenue Increase
Based on Pro forma Operating Results
Original Cost Rate Base Estimated at June 30, 2018

Line No.	Description	Revenue Deficiency
1	Net Original Cost Rate Base	$ 1,250,376,790
2	Rate of Return	6.40%
3	Net Operating Income	80,024,115
4	Pro forma Net Operating Income	16,921,975
5	Increase in Net Operating Income (NOI Shortfall)	63,102,140
6	Effective Incremental Revenuel NOI Conversion Factor	72.929%
7	Increase in Revenue Requirement (Based on Net Original Cost Rate Base) (Line 5 / Line 6)	$ 86,525,127

8	One		1.000000			
9	Less: Public Utility Fee		0.001331			
10	Less: Bad Debt		0.003019			
11	State Taxable Income			0.995650		
12	One	1.000000				
13	Less: IN Utilities Receipts Tax	0.014000				
14	Taxable Adjusted Gross Income Tax		0.995650			
15	Adjusted Gross Income Tax Rate		0.058750			
16	Adjusted Gross Income Tax			0.058494		
17	Line 11 less line 13 less line 16				0.923156	
18	One			1.000000		
19	Less: Federal Income Tax Rate					
20	One Less Federal Income Tax Rate			0.210000		
21	Effective Incremental Revenue / NOI Conversion Factor				0.790000	72.929%

Northern Indiana Public Service Company
Summary of Rate Base
As Of June 30, 2018

Line No.	Description	Pro forma As Of June 30, 2018	Attachment 3-E-S1 Reference
	Rate Base		
1	Utility Plant	2,572,698,416	RB Sch. 1-S1
2	Common Allocated	122,384,028	RB Sch. 1-S1
3	**Total Utility Plant**	2,695,082,444	RB Sch. 1-S1
4			
5	Accumulated Depreciation and Amortization	(1,450,601,872)	RB Sch. 1-S1
6	Common Allocated	(92,269,736)	RB Sch. 1-S1
7	**Total Accumulated Depreciation and Amortization**	(1,542,871,608)	RB Sch. 1-S1
8	**Net Utility Plant**	1,152,210,836	RB Sch. 1-S1
9			
10	TDSIC Regulatory Asset	16,054,127	RB Sch. 1-S1
11	Materials & Supplies	12,014,950	RB Sch. 1-S1
12	Gas Stored Underground - Current A/C 164 (13-mo avg)	62,522,819	RB Sch. 1-S1
13	Gas Stored Underground - Non-Current A/C 117	7,574,058	RB Sch. 1-S1
14	**Total Rate Base**	$ 1,250,376,790	RB Sch. 1-S1

Northern Indiana Public Service Company
June 30, 2018
Capital Structure

Line No.	Description	Total Company Capitalization	Percent of Total	Cost	Weighted Average Cost
	A	B	C	D	E
1	Common Equity	2,610,261,937	45.91%	9.85%	4.52%
2	Long-Term Debt	2,147,947,014	37.78%	4.83%	1.82%
3	Customer Deposits	71,161,098	1.25%	4.91%	0.06%
4	Deferred Income Taxes	1,199,564,996	21.10%	0.00%	0.00%
5	Post-Retirement Liability	87,343,312	1.54%	0.00%	0.00%
6	Prepaid Pension Asset	(434,048,447)	-7.63%	0.00%	0.00%
7	Post-1970 ITC	2,800,573	0.05%	7.58%	0.00%
8	**Totals**	**5,685,030,483**	**100.00%**		**6.40%**

Cost of Investor Supplied Capital

	Description	Total Company Capitalization	Percent of Total	Cost	Weighted Average Cost
	A	B	C	D	E
9	Common Equity	$ 2,610,261,937	54.86%	9.85%	5.40%
10	Long-Term Debt	$ 2,147,947,014	45.14%	4.83%	2.18%
11	**Totals**	**$ 4,758,208,951**	**100.00%**		**7.58%**

Northern Indiana Public Service Company
Statement of Operating Income - Step 2
Actual, Pro forma and Proposed
For the Twelve Month Period Ending December 31, 2018

Line No.	Description	Actual	Pro forma Adjustments Increases (Decreases)	Attachment 3-B-S2 Reference[1]	Pro forma Results Based on Current Rates	Pro forma Adjustments Increases (Decreases)	Attachment 3-D-S2 Reference	Pro forma Results Based on Proposed Rates
	A	B	C	D	E	F	G	H
1	**Operating Revenue**							
2	Revenue (Actual / Pro Forma)	$ 586,736,247		*Rev Sch 1-S3, Col A*	$ 619,371,092	$ 115,726,422	PF - 1-S2	$ 735,097,514
3	Pro forma Adjustments December 31, 2016		25,084,387	*Rev Sch 1-S3, Col B*				
4	Budget Adjustments December 31, 2017		39,185,274	*Rev Sch 1-S3, Col D*				
5	Budget Adjustments December 31, 2018		(1,085,090)	*Rev Sch 1-S3, Col F*				
6	Rate Making Adjustments December 31, 2018		(30,549,726)	*Rev Sch 1-S3, Col H*				
7	Total Operating Revenue	$ 586,736,247	$ 32,634,845		$ 619,371,092	$ 115,726,422		$ 735,097,514
8	**Gas Costs (Trackable)**							
9	Gas Cost (Actual / Pro Forma)	$ 296,774,989		*COGS Sch 1, Col A*	$ 316,907,619	-		$ 316,907,619
10	Pro forma Adjustments December 31, 2016		20,718,747	*COGS Sch 1, Col B*				
11	Budget Adjustments December 31, 2017		17,960,293	*COGS Sch 1, Col D*				
12	Budget Adjustments December 31, 2018		(6,596,838)	*COGS Sch 1, Col F*				
13	Rate Making Adjustments December 31, 2018		(11,949,572)	*COGS Sch 1, Col H*				
14	Total Gas Costs	$ 296,774,989	$ 20,132,630		$ 316,907,619	$ -		$ 316,907,619
15	**Gross Margin**	$ 289,961,258	$ 12,502,215		$ 302,463,473	$ 115,726,422		$ 418,189,895
16	**Operations and Maintenance Expenses**							
17	Operations and Maintenance Expenses (Actual / Pro Forma)	$ 181,866,867		*O&M Sch 1-S3, Col A*	$ 192,612,338	349,430	PF - 2-S2	$ 192,961,768
18	Pro forma Adjustments December 31, 2016		194,118	*O&M Sch 1-S3, Col B*				
19	Budget Adjustments December 31, 2017		13,703,290	*O&M Sch 1-S3, Col D*				
20	Budget Adjustments December 31, 2018		3,573,727	*O&M Sch 1-S3, Col F*				
21	Rate Making Adjustments December 31, 2018		(6,725,664)	*O&M Sch 1-S3, Col H*				
22	Total Operations and Maintenance Expense	$ 181,866,867	$ 10,745,471		$ 192,612,338	$ 349,430		$ 192,961,768
23	**Depreciation Expense**							
24	Depreciation Expense (Actual / Pro Forma)	$ 9,629,139		*Depr Sch 1-R, Col A*	$ 63,943,903			$ 63,943,903
25	Pro forma Adjustments December 31, 2016		-	*Depr Sch 1-R, Col B*				
26	Budget Adjustments December 31, 2017		1,473,118	*Depr Sch 1-R, Col D*				
27	Budget Adjustments December 31, 2018		4,098,076	*Depr Sch 1-R, Col F*				
28	Rate Making Adjustments December 31, 2018		48,743,570	*Depr Sch 1-R, Col H*				
29	Total Depreciation Expense	$ 9,629,139	$ 54,314,764		$ 63,943,903	$ -		$ 63,943,903

Northern Indiana Public Service Company
Statement of Operating Income - Step 2
Actual, Pro forma and Proposed
For the Twelve Month Period Ending December 31, 2018

Line No.	Description	Actual	Pro forma Adjustments Increases (Decreases)	Attachment 3-B-S2 Reference[1]	Pro forma Results Based on Current Rates	Pro forma Adjustments Increases (Decreases)	Attachment 3-D-S2 Reference	Pro forma Results Based on Proposed Rates
	A	B	C	D	E	F	G	H
30	**Amortization Expense**							
31	Amortization Expense (Actual / Pro Forma)	$ 4,650,834		*AMTZ Sch 1-S3, Col A*	$ 8,932,109			$ 8,932,109
32	Pro forma Adjustments December 31, 2016		-	*AMTZ Sch 1-S3, Col B*				
33	Budget Adjustments December 31, 2017		546,330	*AMTZ Sch 1-S3, Col D*				
34	Budget Adjustments December 31, 2018		602,714	*AMTZ Sch 1-S3, Col F*				
35	Rate Making Adjustments December 31, 2018		3,132,231	*AMTZ Sch 1-S3, Col H*				
36	Total Amortization Expense	$ 4,650,834	$ 4,281,275		$ 8,932,109	$ -		$ 8,932,109
37	**Taxes**							
38	**Taxes Other than Income**							
39	Taxes Other than Income (Actual / Pro Forma)	$ 22,416,370		*OTX Sch 1-S3, Col A*	$ 26,963,350			$ 26,963,350
40	Pro forma Adjustments December 31, 2016		351,429	*OTX Sch 1-S3, Col B*				
41	Budget Adjustments December 31, 2017		2,714,626	*OTX Sch 1-S3, Col D*				
42	Budget Adjustments December 31, 2018		1,136,298	*OTX Sch 1-S3, Col F*		$ 1,620,170	PF - 3-S2	$ 1,620,170
43	Rate Making Adjustments December 31, 2018		344,627	*OTX Sch 1-S3, Col H*		$ 154,017	PF - 4-S2	$ 154,017
44	Total Taxes Other Than Income	$ 22,416,370	$ 4,546,980		$ 26,963,350	$ 1,774,187		$ 28,737,537
45	**Operating Income Before Income Taxes**	$ 71,398,048	$ (61,386,275)		10,011,773	$ 113,602,805		$ 123,614,578
46	**Income Taxes**							
47	Federal and State Taxes (Actual / Pro Forma)	$ 21,354,892	$ (25,758,320)	*Attachment 3-D-S2 ITX 1*	$ (4,403,428)	29,204,376	PF - 5-S2	$ 24,800,948
48	Total Taxes	$ 43,771,262	(21,211,340)		$ 22,559,922	$ 30,978,563		$ 53,538,485
49	**Total Operating Expenses including Income Taxes**	$ 239,918,102	$ 48,130,170		$ 288,048,272	$ 31,327,993		$ 319,376,265
50	**Required Net Operating Income**	$ 50,043,156	$ (35,627,955)		$ 14,415,201	$ 84,398,430		$ 98,813,630

Footnote 1 - Unless otherwise noted

Northern Indiana Public Service Company
Calculation of Proposed Revenue Increase
Based on Pro forma Operating Results
Original Cost Rate Base Estimated at December 31, 2018

Line No.	Description	Revenue Deficiency
1	Net Original Cost Rate Base	$ 1,520,209,700
2	Rate of Return	6.50%
3	Net Operating Income	98,813,631
4	Pro forma Net Operating Income	14,415,201
5	Increase in Net Operating Income (NOI Shortfall)	84,398,430
6	Effective Incremental Revenuel NOI Conversion Factor	72.929%
7	Increase in Revenue Requirement (Based on Net Original Cost Rate Base) (Line 5 / Line 6)	$ 115,726,422

8	One		1.000000			
9	Less: Public Utility Fee		0.001331			
10	Less: Bad Debt		0.003019			
11	State Taxable Income			0.995650		
12	One	1.000000				
13	Less: IN Utilities Receipts Tax	0.014000				
14	Taxable Adjusted Gross Income Tax		0.995650			
15	Adjusted Gross Income Tax Rate		0.058750			
16	Adjusted Gross Income Tax			0.058494		
17	Line 11 less line 13 less line 16				0.923156	
18	One			1.000000		
19	Less: Federal Income Tax Rate					
20	One Less Federal Income Tax Rate			0.210000		
21	Effective Incremental Revenue / NOI Conversion Factor				0.790000	72.929%

Northern Indiana Public Service Company
Summary of Rate Base
As Of December 31, 2018

Line No.	Description	Pro forma As Of December 31, 2018	Attachment 3-E-R Reference
	Rate Base		
1	Utility Plant	2,804,946,993	RB Sch. 1-R
2	Common Allocated	126,286,724	RB Sch. 1-R
3	**Total Utility Plant**	2,931,233,717	RB Sch. 1-R
4			
5	Accumulated Depreciation and Amortization	(1,430,397,183)	RB Sch. 1-R
6	Common Allocated	(94,499,023)	RB Sch. 1-R
7	**Total Accumulated Depreciation and Amortization**	(1,524,896,206)	RB Sch. 1-R
8	**Net Utility Plant**	1,406,337,511	RB Sch. 1-R
9			
10	TDSIC Regulatory Asset	20,150,178	RB Sch. 1-R
11	Materials & Supplies	12,532,339	RB Sch. 1-R
12	Gas Stored Underground - Current A/C 164 (13-mo avg)	73,615,614	RB Sch. 1-R
13	Gas Stored Underground - Non-Current A/C 117	7,574,058	RB Sch. 1-R
14	**Total Rate Base**	$ 1,520,209,700	RB Sch. 1-R

Northern Indiana Public Service Company
December 31, 2018
Capital Structure

Line No.	Description	Total Company Capitalization	Percent of Total	Cost	Weighted Average Cost
	A	B	C	D	E
1	Common Equity	2,736,671,686	46.88%	**9.85%**	4.62%
2	Long-Term Debt	2,148,155,424	36.80%	4.94%	1.82%
3	Customer Deposits	71,161,098	1.22%	4.91%	0.06%
4	Deferred Income Taxes	1,231,667,566	21.10%	0.00%	0.00%
5	Post-Retirement Liability	81,037,285	1.39%	0.00%	0.00%
6	Prepaid Pension Asset	(433,528,447)	-7.43%	0.00%	0.00%
7	Post-1970 ITC	2,671,039	0.04%	7.69%	0.00%
8	**Totals**	**5,837,835,651**	**100.00%**		**6.50%**

Cost of Investor Supplied Capital

	Description	Total Company Capitalization	Percent of Total	Cost	Weighted Average Cost
	A	B	C	D	E
9	Common Equity	$ 2,736,671,686	56.02%	9.85%	5.52%
10	Long-Term Debt	$ 2,148,155,424	43.98%	4.94%	2.17%
11	**Totals**	**$ 4,884,827,110**	**100.00%**		**7.69%**

Northern Indiana Public Service Company
Statement of Operating Income - Step 3
Actual, Pro forma and Proposed
For the Twelve Month Period Ending December 31, 2018

Line No.	Description	Actual	Pro forma Adjustments Increases (Decreases)	Attachment 3-B-S3 Reference[1]	Pro forma Results Based on Current Rates	Pro forma Adjustments Increases (Decreases)	Attachment 3-D-S3 Reference	Pro forma Results Based on Proposed Rates
	A	B	C	D	E	F	G	H
1	**Operating Revenue**							
2	Revenue (Actual / Pro Forma)	$ 586,736,247		*Rev Sch 1-S3, Col A*	$ 619,371,092	107,300,001	PF - 1-S3	$ 726,671,093
3	Pro forma Adjustments December 31, 2016		25,084,387	*Rev Sch 1-S3, Col B*				
4	Budget Adjustments December 31, 2017		39,185,274	*Rev Sch 1-S3, Col D*				
5	Budget Adjustments December 31, 2018		(1,085,090)	*Rev Sch 1-S3, Col F*				
6	Rate Making Adjustments December 31, 2018		(30,549,726)	*Rev Sch 1-S3, Col H*				
7	Total Operating Revenue	$ 586,736,247	$ 32,634,845		$ 619,371,092	$ 107,300,001		$ 726,671,093
8	**Gas Costs (Trackable)**							
9	Gas Cost (Actual / Pro Forma)	$ 296,774,989		*COGS Sch 1, Col A*	$ 316,907,619	-		$ 316,907,619
10	Pro forma Adjustments December 31, 2016		20,718,747	*COGS Sch 1, Col B*				
11	Budget Adjustments December 31, 2017		17,960,293	*COGS Sch 1, Col D*				
12	Budget Adjustments December 31, 2018		(6,596,838)	*COGS Sch 1, Col F*				
13	Rate Making Adjustments December 31, 2018		(11,949,572)	*COGS Sch 1, Col H*				
14	Total Gas Costs	$ 296,774,989	$ 20,132,630		$ 316,907,619	$ -		$ 316,907,619
15	**Gross Margin**	$ 289,961,258	$ 12,502,215		$ 302,463,473	$ 107,300,001		$ 409,763,474
16	**Operations and Maintenance Expenses**							
17	Operations and Maintenance Expenses (Actual / Pro Forma)	$ 181,866,867		*O&M Sch 1-S3, Col A*	$ 192,612,338	323,987	PF - 2-S3	$ 192,936,325
18	Pro forma Adjustments December 31, 2016		194,118	*O&M Sch 1-S3, Col B*				
19	Budget Adjustments December 31, 2017		13,703,290	*O&M Sch 1-S3, Col D*				
20	Budget Adjustments December 31, 2018		3,573,727	*O&M Sch 1-S3, Col F*				
21	Rate Making Adjustments December 31, 2018		(6,725,664)	*O&M Sch 1-S3, Col H*				
22	Total Operations and Maintenance Expense	$ 181,866,867	$ 10,745,471		$ 192,612,338	$ 323,987		$ 192,936,325
23	**Depreciation Expense**							
24	Depreciation Expense (Actual / Pro Forma)	$ 9,629,139		*Depr Sch 1-R, Col A*	$ 63,943,903			$ 63,943,903
25	Pro forma Adjustments December 31, 2016		-	*Depr Sch 1-R, Col B*				
26	Budget Adjustments December 31, 2017		1,473,118	*Depr Sch 1-R, Col D*				
27	Budget Adjustments December 31, 2018		4,098,076	*Depr Sch 1-R, Col F*				
28	Rate Making Adjustments December 31, 2018		48,743,570	*Depr Sch 1-R, Col H*				
29	Total Depreciation Expense	$ 9,629,139	$ 54,314,764		$ 63,943,903	$ -		$ 63,943,903

Northern Indiana Public Service Company
Statement of Operating Income - Step 3
Actual, Pro forma and Proposed
For the Twelve Month Period Ending December 31, 2018

Line No.	Description	Actual	Pro forma Adjustments Increases (Decreases)	Attachment 3-B-S3 Reference[1]	Pro forma Results Based on Current Rates	Pro forma Adjustments Increases (Decreases)	Attachment 3-D-S3 Reference	Pro forma Results Based on Proposed Rates
	A	B	C	D	E	F	G	H
30	**Amortization Expense**							
31	Amortization Expense (Actual / Pro Forma)	$ 4,650,834		*AMTZ Sch 1-S3, Col A*	$ 8,932,109			$ 8,932,109
32	Pro forma Adjustments December 31, 2016		-	*AMTZ Sch 1-S3, Col B*				
33	Budget Adjustments December 31, 2017		546,330	*AMTZ Sch 1-S3, Col D*				
34	Budget Adjustments December 31, 2018		602,714	*AMTZ Sch 1-S3, Col F*				
35	Rate Making Adjustments December 31, 2018		3,132,231	*AMTZ Sch 1-S3, Col H*				
36	Total Amortization Expense	$ 4,650,834	$ 4,281,275		$ 8,932,109	$ -		$ 8,932,109
37	**Taxes**							
38	**Taxes Other than Income**							
39	Taxes Other than Income (Actual / Pro Forma)	$ 22,416,370		*OTX Sch 1-S3, Col A*	$ 26,963,350			$ 26,963,350
40	Pro forma Adjustments December 31, 2016		351,429	*OTX Sch 1-S3, Col B*				
41	Budget Adjustments December 31, 2017		2,714,626	*OTX Sch 1-S3, Col D*				
42	Budget Adjustments December 31, 2018		1,136,298	*OTX Sch 1-S3, Col F*		$ 1,502,200	PF - 3-S3	$ 1,502,200
43	Rate Making Adjustments December 31, 2018		344,627	*OTX Sch 1-S3, Col H*		$ 142,802	PF - 4-S3	$ 142,802
44	Total Taxes Other Than Income	$ 22,416,370	$ 4,546,980		$ 26,963,350	$ 1,645,002		$ 28,608,352
45	**Operating Income Before Income Taxes**	$ 71,398,048	$ (61,386,275)		10,011,773	$ 105,331,012		$ 115,342,785
46	**Income Taxes**							
47	Federal and State Taxes (Actual / Pro Forma)	$ 21,354,892	$ (31,903,647)	*Attachment 3-D-S3 ITX 1*	$ (10,548,755)	27,077,909	PF - 5-S3	$ 16,529,154
48	Total Taxes	$ 43,771,262	(27,356,667)		$ 16,414,595	$ 28,722,911		$ 45,137,506
49	**Total Operating Expenses including Income Taxes**	$ 239,918,102	$ 41,984,843		$ 281,902,945	$ 29,046,898		$ 310,949,843
50	**Required Net Operating Income**	$ 50,043,156	$ (29,482,628)		$ 20,560,528	$ 78,253,103		$ 98,813,631

Footnote 1 - Unless otherwise noted

Northern Indiana Public Service Company
Calculation of Proposed Revenue Increase
Based on Pro forma Operating Results
Original Cost Rate Base Estimated at December 31, 2018

Line No.	Description	Revenue Deficiency
1	Net Original Cost Rate Base	$ 1,520,209,700
2	Rate of Return	6.50%
3	Net Operating Income	98,813,631
4	Pro forma Net Operating Income	20,560,528
5	Increase in Net Operating Income (NOI Shortfall)	78,253,103
6	Effective Incremental Revenuel NOI Conversion Factor	72.929%
7	Increase in Revenue Requirement (Based on Net Original Cost Rate Base) (Line 5 / Line 6)	$ 107,300,001

8	One		1.000000			
9	Less: Public Utility Fee		0.001331			
10	Less: Bad Debt		0.003019			
11	State Taxable Income			0.995650		
12	One	1.000000				
13	Less: IN Utilities Receipts Tax	0.014000				
14	Taxable Adjusted Gross Income Tax		0.995650			
15	Adjusted Gross Income Tax Rate		0.058750			
16	Adjusted Gross Income Tax			0.058494		
17	Line 11 less line 13 less line 16				0.923156	
18	One			1.000000		
19	Less: Federal Income Tax Rate					
20	One Less Federal Income Tax Rate			0.210000		
21	Effective Incremental Revenue / NOI Conversion Factor				0.790000	72.929%

Northern Indiana Public Service Company
Summary of Rate Base
As Of December 31, 2018

Line No.	Description	Pro forma As Of December 31, 2018	Attachment 3-E-R Reference
	Rate Base		
1	Utility Plant	2,804,946,993	RB Sch. 1-R
2	Common Allocated	126,286,724	RB Sch. 1-R
3	**Total Utility Plant**	2,931,233,717	RB Sch. 1-R
4			
5	Accumulated Depreciation and Amortization	(1,430,397,183)	RB Sch. 1-R
6	Common Allocated	(94,499,023)	RB Sch. 1-R
7	**Total Accumulated Depreciation and Amortization**	(1,524,896,206)	RB Sch. 1-R
8	**Net Utility Plant**	1,406,337,511	RB Sch. 1-R
9			
10	TDSIC Regulatory Asset	20,150,178	RB Sch. 1-R
11	Materials & Supplies	12,532,339	RB Sch. 1-R
12	Gas Stored Underground - Current A/C 164 (13-mo avg)	73,615,614	RB Sch. 1-R
13	Gas Stored Underground - Non-Current A/C 117	7,574,058	RB Sch. 1-R
14	**Total Rate Base**	$ 1,520,209,700	RB Sch. 1-R

Northern Indiana Public Service Company
December 31, 2018
Capital Structure

Line No.	Description	Total Company Capitalization	Percent of Total	Cost	Weighted Average Cost
	A	B	C	D	E
1	Common Equity	2,736,671,686	46.88%	**9.85%**	4.62%
2	Long-Term Debt	2,148,155,424	36.80%	4.94%	1.82%
3	Customer Deposits	71,161,098	1.22%	4.91%	0.06%
4	Deferred Income Taxes	1,231,667,566	21.10%	0.00%	0.00%
5	Post-Retirement Liability	81,037,285	1.39%	0.00%	0.00%
6	Prepaid Pension Asset	(433,528,447)	-7.43%	0.00%	0.00%
7	Post-1970 ITC	2,671,039	0.04%	7.69%	0.00%
8	**Totals**	**5,837,835,651**	**100.00%**		**6.50%**

Cost of Investor Supplied Capital

	Description	Total Company Capitalization	Percent of Total	Cost	Weighted Average Cost
	A	B	C	D	E
9	Common Equity	$ 2,736,671,686	56.02%	9.85%	5.52%
10	Long-Term Debt	$ 2,148,155,424	43.98%	4.94%	2.17%
11	**Totals**	**$ 4,884,827,110**	**100.00%**		**7.69%**

Joint Exhibit D
Stipulation and Settlement Agreement
Cause No. 44988

Northern Indiana Public Service Company
Settlement Revenue Requirement Mitigation

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
			rebuttal	rebuttal	((G) / (G line 9)) * (E line1)		(C) * (F)	(C) + (E) + (G)	Percent of Total (column H)
Line	STEP 3 Class		Total Margin - Current	Rebuttal ACOSS Total Margin at Equal Rates of Return	Revenue Adjustment	Settlement Margin Increase (%)	Settlement Margin Increase ($)	Settlement Total Step 3 Margin ($)	Resulting Rate Class Percentage of Base Rate Margin
1	System Total		$ 291,797,594	$429,730,539	$ 4,012,115	36.21%	$ 107,300,000	$ 402,908,450	100.00%
2	Residential	411	$ 186,593,282	$275,385,307	$ 2,565,592	36.21%	$ 68,485,505	$ 257,644,380	63.95%
3	Multi-Family	415	$ 2,171,463	$ 2,379,497	$ 2,213	2.72%	$ 59,064	$ 2,232,739	0.55%
4	General Service Small	421	$ 61,660,536	$ 76,036,005	$ 883,366	37.70%	$ 23,580,422	$ 86,124,324	21.38%
5	General Service Large	425	$ 10,543,808	$ 11,531,473	$ 109,633	27.47%	$ 2,926,525	$ 13,579,966	3.37%
6	Large Transp.	428	$ 27,104,749	$ 60,019,889	$ 401,658	38.98%	$ 10,721,786	$ 38,228,193	9.49%
7	C&I Off-Peak Interruptib	434	$ 368,385	$ 93,653	$ -	0.00%	$ -	$ 368,385	0.09%
8	General Transportation	438	$ 3,355,371	$ 4,284,714	$ 49,653	38.93%	$ 1,325,439	$ 4,730,463	1.17%
9	Sub-Total		$ 291,797,594	$429,730,539	$ 4,012,115	36.21%	$ 107,098,741	$ 402,908,450	100.00%
10	iscellaneous Revenues Margin		$ 6,653,764	$ 6,855,023		Misc. Rev. Margin	$ 201,259	$ 6,855,023	
11	Total Margin		$ 298,451,358	$436,585,562		Total Margin	$ 107,300,000	$ 409,763,473	
12					150% Sys. Incr.=	54.31%			

(K)	(L)	(M)	(N)	(O)	(P)	(Q)
				(H) * ((K) / (D))	(H) * ((L) / (D))	(H) * ((M) / (D))
	Before Mitigation			After Mitigation		
Class	Rebuttal ACOSS Customer Component	Rebuttal ACOSS Demand Component	Rebuttal ACOSS Commodity Component	Settlement Customer Component	Settlement Demand Component	Settlement Commodity Component
System Total	$ 251,392,183	$ 166,099,262	$ 12,239,094	$ 242,582,803	$ 148,287,077	$ 12,038,571
111	$ 198,573,865	$ 70,829,533	$ 5,981,910	$ 185,781,300	$ 66,266,538	$ 5,596,542
115	$ 1,486,503	$ 833,751	$ 59,243	$ 1,394,822	$ 782,329	$ 55,589
121	$ 40,391,301	$ 32,122,703	$ 3,522,001	$ 45,750,345	$ 36,384,685	$ 3,989,294
125	$ 2,782,330	$ 7,502,526	$ 1,246,616	$ 3,276,593	$ 8,835,303	$ 1,468,070
128	$ 6,093,047	$ 52,529,865	$ 1,396,977	$ 3,880,816	$ 33,457,606	$ 889,770
134	$ 77,381	$ 15,002	$ 1,270	$ 304,380	$ 59,009	$ 4,997
138	$ 1,987,756	$ 2,265,881	$ 31,076	$ 2,194,547	$ 2,501,606	$ 34,309

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
					((G) / (G line 4)) * (E line1)	(G) / (C)		(C) + (E) + (G)		(H) - (I)
Line	STEP 3 Class		Total Margin - Current	Rebuttal ACOSS Total Margin at Equal Rates of Return	Revenue Adjustment	Settlement Margin Increase (%)	Settlement Margin Increase ($)	Settlement Total Step 3 Margin ($)	Less Pooling and Nomination Revenues	Targeted Base Rate Step 3 Margin
1	Large Transp.	428	$ 27,104,749	$ 60,019,889	$ 401,658	38.98%	10,721,786	38,228,193	875,254	37,352,939
2	Large Transp. - DP	428a	$ 6,337,196	$ 18,397,444	$ 116,111	48.03%	3,099,452	9,552,759	207,858	9,344,901
3	Large Transp. - HP	428b	$ 20,767,553	$ 41,622,446	$ 285,547	36.21%	7,622,334	28,675,434	667,397	28,008,038
4	428a and 428b Total		$ 27,104,749	$ 60,019,889	$ 401,658		10,721,786	38,228,193	875,254	37,352,939
5	Delta		-	0			0	-	(0)	0

(K)	(L)	(M)	(N)	(O)	(P)	(Q)
				(H) * ((K) / (D))	(H) * ((L) / (D))	(H) * ((M) / (D))
	Before Mitigation			After Mitigation		
Class	Rebuttal ACOSS Customer Component	Rebuttal ACOSS Demand Component	Rebuttal ACOSS Commodity Component	Settlement Customer Component	Settlement Demand Component	Settlement Commodity Component
Rate 128	6,093,047	52,529,865	1,396,977	3,880,816	33,457,606	889,770
Distribution Pressur	2,741,877	15,507,925	147,641	1,423,703	8,052,394	76,662
High Pressure	3,365,968	37,011,891	1,244,587	2,318,955	25,499,031	857,448

Joint Exhibit D
Stipulation and Settlement Agreement
Cause No. 44988

	(A)	(B)	(C)	(D)	(E)	(F)	(G)
					(C) * (1 + (D))		(E) * (1 + (F))
			STEP 1		STEP 2		STEP 3
Line	Class		6/30/18 Proposed Margin	Equalized Increase Step 1 to Step 2	12/31/18 Proposed Margin	Equalized Reduction Step 2 to Step 3	12/31/18 Settlement Final Proposed Margin
1	System Total		$ 382,133,577		$ 411,334,872		$ 402,908,450
2	Residential	111	244,359,652	7.64%	263,032,751	-2.05%	257,644,380
3	Multi-Family	115	2,117,614	7.64%	2,279,435	-2.05%	2,232,739
4	General Service Small	121	81,683,558	7.64%	87,925,527	-2.05%	86,124,324
5	General Service Large	125	12,879,752	7.64%	13,863,977	-2.05%	13,579,966
6	Large Transp.	128	36,257,061	7.64%	39,027,697	-2.05%	38,228,193
7	Large Transp. - DP	128a	9,060,197	7.64%	9,752,545	-2.05%	9,552,759
8	Large Transp. - HP	128b	27,196,864	7.64%	29,275,152	-2.05%	28,675,434
9	C&I Off-Peak Interruptib	134	349,390	7.64%	376,090	-2.05%	368,385
10	General Transportation	138	4,486,549	7.64%	4,829,396	-2.05%	4,730,463
11	iscellaneous Revenues Margin		6,855,023		6,855,023		$ 6,855,023
12	Total Margin		$ 388,988,600		$ 418,189,895		$ 409,763,473

Northern Indiana Public Service Company LLC
Gas TDSIC Allocators

Rates		Margin		Gas Costs		Revenue	Allocators
111	$	255,246,231	$	207,808,679	$	463,054,910	64.69%
115	$	2,356,890	$	2,403,993	$	4,760,883	0.67%
121/134	$	85,613,191	$	84,370,019	$	169,983,210	23.75%
125	$	13,470,950	$	20,731,302	$	34,202,252	4.78%
128	$	37,546,011	$	1,433,892	$	38,979,903	5.45%
138	$	4,681,019	$	158,639	$	4,839,658	0.68%
	$	398,914,292	$	316,906,524	$	715,820,816	
							100.00%

Northern Indiana Public Service Company LLC
Gas FMCA Allocators

Rates		Allocation
(A)	(B)	(C)
111	$ 224,178,261	55.6%
115	$ 2,256,287	0.6%
121/134	$ 71,717,704	17.8%
125	$ 11,966,381	3.0%
128	$ 88,639,859	22.0%
138	$ 4,149,957	1.0%
Total	$ 402,908,450	100.0%

Confidential Joint Exhibit G (Redacted)
Stipulation and Settlement Agreement
Cause No. 44988

NIPSCO Pipeline Safety Compliance Plan

Project No.	Project Name	2018 Capital Direct ($)	2019 Capital Direct ($)	2020 Capital Direct ($)	2021 Capital Direct ($)	Total Capital Direct ($)	2018 Annual O&M Direct ($)	2019 Annual O&M Direct ($)	2020 Annual O&M Direct ($)	2021 Annual O&M Direct ($)	Total O&M Direct ($)	Total Project ($)
PS1	TIMP Programmatic Improvements Project	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$551,000
PS2	Management of Change Project	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$81,611
PS3	Preventive and Mitigative Measures Project	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$418,363
PS4	Annual Plan Improvements Project	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$125,509
PS5	Enhanced Emergency Responder Outreach Program	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$400,000
PS6	DIMP Administration / Leak Data Verification Project	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$568,782
PS7	Service Card Enhancements Project	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$8,243,216
PS8	Fiberglass Riser Replacement Project	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$8,961,551
PS9	Legacy Cross Bore Remediation Project	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$877,903
PS10	Underground Storage Integrity Project	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$2,858,947
PS11	Farm Tap Remediation Project	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$3,545,930
PS12	ILI Project	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$48,840,968
PS13	Transmission Inspect & Mitigate Project	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$3,458,317
PS14	AC Mitigation Project	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$5,013,568
PS15	Transmission RCV Installation Project	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$2,235,118
PS16	Isolated Services Project	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$3,900,644
PS17	Emergency Valve Project	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$4,644,023
PS18	Casings Project	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$475,840
	Casings Project	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$2,733,215
PS19	Distribution Inspect & Mitigate Project	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$2,969,471
PS20 (OM 2D)	Transmission Risk Modeling	$0	$0	$0	$0	$0	$300,000	$300,000	$300,000	$300,000	$1,200,000	$1,200,000
PS21 (OM2F)	Legacy Cross Bore Inspection	$0	$0	$0	$0	$0	$806,200	$806,200	$806,200	$806,200	$3,224,800	$3,224,800
PS22 (OM2R)	Test Station Casings	$0	$0	$0	$0	$0	$350,000	$350,000	$350,000	$350,000	$1,400,000	$1,400,000
PS23 (OM 2H)	MAOP - Distribution	$0	$0	$0	$0	$0	$500,000	$500,000	$500,000	$500,000	$2,000,000	$2,000,000
PS24 (OM 2I)	MAOP - Transmission	$0	$0	$0	$0	$0	$1,250,000	$1,250,000	$1,250,000	$1,250,000	$5,000,000	$5,000,000
	Pipeline Safety Compliance Plan Direct Costs	$1,713,042	$25,599,272	$22,792,200	$28,124,534	$78,229,048	$9,120,111	$8,713,097	$8,782,750	$8,883,769	$35,499,727	$113,728,775
	Indirect Costs	$208,648	$4,139,402	$3,421,109	$2,984,013	$10,753,172						$10,753,172
	AFUDC					$2,511,444						$2,511,444
	Total Pipeline Safety Compliance Plan					$91,493,664						$126,993,391